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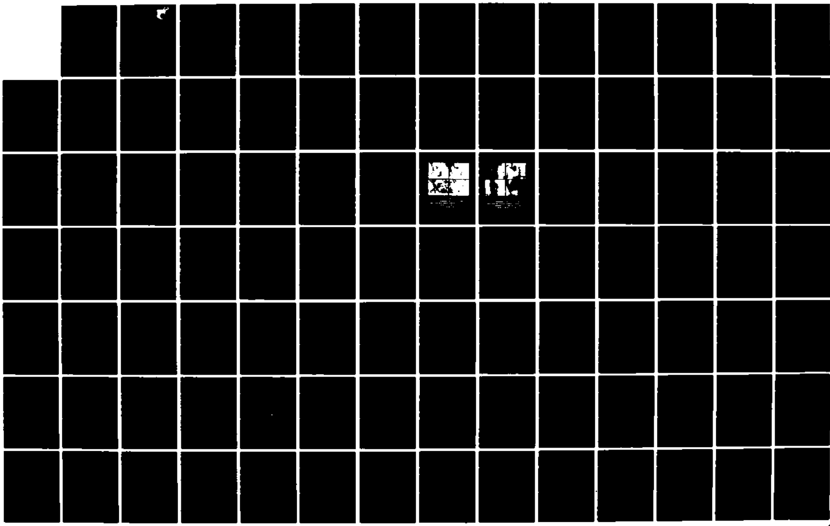

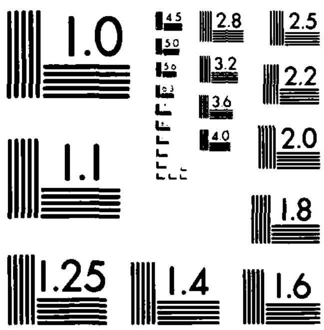

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AFWAL-TR-81-2116
Volume II

USAF SHALE OIL TO FUELS
Volume II. Phases III and IV

UOP INC.
ALGONQUIN AND MT. PROSPECT ROADS
DES PLAINES, ILLINOIS 60016

JULY 1982

FINAL REPORT FOR PERIOD 1 OCTOBER 1980 - 31 DECEMBER 1981

Approved for public release; distribution unlimited

AERO PROPULSION LABORATORY
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This technical report has been reviewed and is approved for publication.

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The overall objective of this project was to demonstrate innovative technology to reduce the cost of converting shale oil to high yields of aviation turbine fuels. To carry out this program, UOP selected a processing scheme involving two stages of hydrotreating followed by hydrocracking. The Phase III and IV programs included first-stage hydrotreating catalyst stability testing; the production of jet and diesel fuel samples using the hydrocracking process; naphtha hydrotreating and catalytic reforming; arsenic management studies; an investigation of shale oil fouling, a shale oil/petroleum stability/compatibility study, and an economic analysis of the proposed upgrading scheme.

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The novel hydrocracking scheme was successful in producing high quality jet fuel samples. A comparison of some key product properties with the specifications shows:

	JP-4		JP-8	
	Spec.	Product	Spec.	Product
Sp. Gr. 60/60°F	0.751-0.802	0.7813	0.775-0.840	0.7972
Smoke Point	20	28.5	25	27.2
Aromatics, vol-%	25	8.7	25	9.3
Combustion, Btu/lb.	18,400	18,700	18,400	18,600

Based on yields and operating conditions demonstrated in pilot plant operations, process designs were prepared for the first- and second-stage hydrotreaters and the hydrocracker. These designs along with the information for the other process units were incorporated into a linear program model for a shale oil refinery. Using the basis provided by the USAF and assuming 100,000 barrels per stream day (BPSD) of raw shale oil valued at $40/B, the following results were obtained:

	Max. JP-4	Max. JP-8
Jet Fuel Yield, BPSD	91,760	80,742
Total Liquid Product Yield	91,760	89,591
Capital Investment, MM $	902	939
Product Cost, $/B of Total Liquid Product	56.82	58.80

FOREWORD

The final report describes the work completed by UOP Inc. on Phases III and IV of the Contract No. F33615-78-C-2079 entitled "United States Air Force Shale Oil to Fuels."

First Lieutenant Edward N. Coppola was the project engineer for the Air Force Wright Aeronautical Laboratories.

The work reported herein was performed during the period 1 October 1980 - 31 December 1981 under the direction of A. O. Braun and J. R. Wilcox. This report was submitted to the USAF in April, 1982.

The following individuals contributed to the execution of the program and the preparation of the report material:

Lee Hilfman, E. J. Latos, and J. G. Gatsis; all of the Corporate Research Center, UOP Inc.;
J. G. Sikonia, T. G. Board, V. A. Gembicki, J. R. Wilcox and Edwin Yuh; all of the Process Division of UOP Inc.

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LIST OF SYMBOLS

Symbols	
A	Aromatics in FIA Analysis
AAS	Atomic Absorption Spectroscopy
B	Barrel
BFW	Boiler Feed Water
BPCD	Barrels per Calendar Day
BPSD	Barrels per Stream Day
Btu/lb	British Thermal Units per Pound
BTX	Benzene, Toluene, Xylene
°C	Degrees Celsius
C	Combined Feed Ratio
C_B	Combined Feed Ratio of Base Operation
CFR	Combined Feed Ratio, Vol. Feed Rate/(Feed Rate + Recycle Rate)
cSt	Centistoke
DCF	Discounted Cash Flow
dR_F/dt	Fouling Rate
EEC	Estimated Erected Cost
EFCEST	Engineering for Cost Estimating
EP	End Point of Distillation
EPA	U.S. Environmental Protection Agency
°F	Degrees Fahrenheit
FIA	Fluorescent-Indicator Adsorption
gal	Gallon
GC	Gas Chromatograph
h	Heat Transfer Coefficient
H	H_2 Recycle Ratio in SCFB
H_B	H_2 Recycle Ratio of Base Operation
HP	High Pressure (Steam)
K	Degrees Kelvin
kWh	Kilowatt Hour
L	Liquid Hourly Space Velocity, LHSV
L_B	LHSV of Base Operation
LHSV	Liquid Hourly Space Velocity
LP	Low Pressure (Steam)
LP	Linear Programming
MON	Motor Octane Number
mL	Milliliter
MM $	Millions of U.S. Dollars
MP	Medium Pressure (Steam)

LIST OF SYMBOLS

Symbols	
N	Naphthenes in FIA Analysis
O	Olefins in FIA Analysis
P	Paraffins in FIA Analysis
P	Pressure
P_B	Pressure of Base Operation
ppm	Parts per Million
psig	Pressure, Pounds per Square Inch Gauge
Q	Heat Input
R_F	Fouling Factor
RON	Research Octane Number
RONC	Research Octane Number Clear (no lead addition)
R+M/2	Average of Research and Motor Octane Numbers
RVP	Reid Vapor Pressure
SCFB	Standard Cubic Feet per Barrel
SCFD	Standard Cubic Feet per Day
SEM	Scanning Electron Microscope
Sp. Gr.	Specific Gravity
ST/D	Short Tons per Day
SUS	Saybolt Universal Seconds
T	Temperature
T_B	Temperature of Base Operation
TEL	Tetra-ethyl Lead
T_F	Fluid Temperature
F_W	Wire Temeprature
vol-%	Volume Percent
wt-%	Weight Percent

SUMMARY

The overall objective of this project was to demonstrate innovative technology to reduce the cost of converting shale oil to high yields of aviation turbine fuels. To carry out this program, UOP selected a processing scheme involving two stages of hydrotreating followed by hydrocracking. The Phase III and IV programs included first-stage hydrotreating catalyst stability testing, the production of jet and diesel fuel samples using the hydrocracking process, naphtha hydrotreating and catalytic reforming, arsenic management studies, an investigation of shale oil fouling, a shale oil/petroleum stability/compatibility study, and an economic analysis of the proposed upgrading scheme.

Based on the results of a six-month, first-stage hydrotreating operation, it was concluded that the catalyst showed excellent stability for arsenic and iron removal, and that high concentrations of contaminants could be contained. Fouling noted in the pilot plant preheater must be considered in a commercial design.

The novel hydrocracking scheme was successful in producing high quality jet fuel samples. A comparison of some key product properties with the specifications shows:

	JP-4		JP-8	
	Spec.	Product	Spec.	Product
Sp. Gr. 60/60°F	0.751-0.802	0.7813	0.775-0.840	0.7972
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Aromatics, vol-%	25	8.7	25	9.3
Combustion, Btu/lb	18,400	18,700	18,400	18,600

Catalytic reforming of the naphtha produced in the hydrocracking operation showed this material to be comparable to petroleum feedstocks and give C_5 plus liquid yields of 85 and 70 vol-% at 89 and 104 Research octane numbers (clear), respectively.

The aqueous solubility of arsenic on the used hydrotreating catalyst was found to exceed the acceptable level in the EPA Toxicity test. The arsenic-containing species were identified, thermal and chemical passivation and extraction techniques were investigated, and recommendations for further work were formulated.

Fouling studies showed that freshly produced samples would probably be much more reactive than the samples tested and that hydrotreating decreases the fouling tendency. A study of the compatibility and stability of blends of shale oils and petroleum showed no serious problems.

Based on yields and operating conditions demonstrated in pilot plant operations, process designs were prepared for the first- and second-stage hydrotreaters and the hydrocracker. These designs along with the information for the other process units were incorporated into a linear program

model for a shale oil refinery. Using the basis provided by the USAF and assuming 100,000 barrels per stream day (BPSD) of raw shale oil valued at $40/B, the following results were obtained:

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SECTION I

INTRODUCTION

This study was conducted to develop yield and economic data for the conversion of shale oil to aviation turbine fuels using innovative processing techniques. A processing scheme maximizing the yield of jet fuels at minimum cost was developed during Phase I of this program. This scheme consisted of the primary shale oil upgrading and conversion units with the necessary auxiliary facilities. The primary units include two stages of upgrading utilizing proprietary RCD Unibon® technology combined with UOP Hydrotreating technology. The upgraded shale oil is then converted to high yields of jet fuel using a novel, "parallel-flow" hydrocracking operation included in the UOP proprietary HC Unibon® technology.

The UOP approach to the problem of shale oil conversion to high quality fuels involves three distinct hydroprocessing steps. Shale oil has unique characteristics relative to conventional crude petroleum oil. Unusually high arsenic and iron levels, high pour point and viscosity, a high unsaturates concentration, and a significant solids (ash) content make conventional front-end refining techniques unusable without proper pretreatment.

The initial step in the UOP scheme is a feed preparation procedure which is essentially a desalting operation. The pilot plant utilized for this operation is completely analogous to a two-stage desalting unit commonly used in the refining industry.

After desalting, the first hydroprocessing step involves the use of UOP's RCD Unibon technology to effect metals removal, sulfur reduction, a degree of diolefin and olefin saturation, and the final solids clean-up necessary to render the resulting effluent suitable for subsequent processing.

Another characteristic of shale oil is its high nitrogen content relative to conventional crude oil. Reducing this contaminant to acceptable levels requires the use of a second-stage, high severity hydrotreatment of the first-stage hydrotreater effluent.

Once the metals, other contaminants and nitrogen contents have been reduced to acceptable levels and the unsaturates hydrogenated, shale oil is ready for the primary conversion step -- hydrocracking to jet and other fuels. The hydrocracking process that UOP has selected is a parallel-flow hydrocracker developed for conventional petroleum use.

Although jet fuel is the primary product in the overall refinery developed by UOP, diesel fuel and naphtha can also be produced. The naphtha was split into light and heavy fractions, with the heavy fraction converted to a gasoline component by reforming via a UOP Platforming® process unit. The reformate was mixed with the light naphtha fraction and sufficient butanes to produce the finished gasoline.

Phase I of the program provided for the development of innovative processing techniques and associated information for the conversion of shale oil to high yields of jet fuel. Phase II was primarily a test program utilizing small scale pilot plants to demonstrate the processing techniques developed in Phase I. The following summarizes the specific objectives for Phase II:

- Characterization of feedstock
- Determination of the shale oil fouling characteristics
- Preparation of sufficient feedstock to explore parallel-flow hydrocracking operating parameters
- Exploration of first- and second-stage hydrotreating operating parameters and catalyst systems
- Production of small scale jet fuel product samples

- Verification and/or adjustment of the operating requirement and product quality estimates generated during Phase I

- Establishment of processing parameter information for the Phase IV Economic Evaluation Study

Two feedstocks were used in this phase of the project. The first was shale oil derived from Occidental Petroleum Company's Modified In-Situ retorting process, and the second was shale oil obtained from the above-ground Paraho direct-heated retort. This work was summarized in Report Number AFWAL-TR-81-2116 entitled "United States Air Force Shale Oil to Fuels -- Phase II Interim Report" issued in November, 1981.

The objectives of the Phase III program included:

- Demonstration of first-stage hydrotreater catalyst stability

- Production of 5-gallon samples of jet and diesel fuels using the parallel-flow hydrocracking scheme

- Demonstration of hydrocracker catalyst stability

- Production of a 5-gallon sample of Special Grade gasoline using the Platforming process

- Investigation of crude shale oil arsenic solubilization and passivation or extraction of arsenic from used hydrotreating catalysts

- Determination of the relative fouling characteristics of raw and hydroprocessed shale oil fractions

- Examination of the stability and compatibility of shale oil and petroleum blends

The objectives of the Phase IV program included:

- Production of cost estimate based on process designs for the first-stage hydrotreater, second-stage hydrotreater and hydrocracker.

- Development of a shale oil refinery model

- Analysis of the economics of jet fuel production from raw shale oil

The results of the Phase III and Phase IV programs are contained in this final report.

The various operating conditions used during the pilot plant studies are consistent with commercial operating experience based on petroleum derived oils. All of the data presented in this report have operating conditions reported relative to a base operating condition. In all cases, the base conditions selected are those required to process a typical Middle East petroleum of the same boiling range to the identical product requirements. Positive differences in operating conditions indicate more severe requirements; negative differences indicate less severe processing requirements.

SECTION II

FIRST-STAGE HYDROTREATING

A six-month, first-stage hydrotreating run was made to provide additional processing and catalyst stability data required to establish the equipment design for a commercial plant. The specific data needed for this design work were the effect of metals deposition, particularly arsenic and iron, on catalyst activity and stability, when accomplishing the objective of reducing the arsenic content to less than 1 ppm.

Pilot Plant Description

A schematic diagram of the pilot plant used for this run is shown in Figure 1. Fresh feed and hydrogen are combined and flow concurrently downflow over the catalyst. The reactor effluent passes to a series of separators where the gas (mainly hydrogen) is separated, water scrubbed and recycled back to the reactor together with makeup hydrogen. The liquid is sent to a stripper to remove hydrogen sulfide and ammonia and is then collected under nitrogen in a glass receiver.

Based on the previously completed experimental work, the catalyst designated DRA was selected for this run. This proprietary, commercially-proven catalyst was developed to hydrotreat feeds containing large amounts of metal contaminants.

Feedstock

The feedstock was an Occidental shale oil produced from a modified in-situ retort. The "as-received" shale oil was dewatered and desalted in a two-stage electric desalter. Inspections of the treated shale oil are shown in Table 1. This 22.9 °API gravity material contained 1.51 wt-% nitrogen, 27.5 ppm arsenic, and 45 ppm iron.

This feedstock was subjected to inspection throughout the six-month operation. As indicated on Table 2, the API gravity, distillation, and Bromine number show the expected variations in the test results. The values for arsenic show a broad range with many points below the 27.5 ppm level given in Table 1. The 60 ppm iron values in Table 2 are fairly consistent and higher than the 45 ppm level of Table 1.

Operating Conditions

Process conditions used in this study are comparable to those commercially employed for hydrotreating coke-oven light oil. The nomenclature adopted to relate the actual operating conditions to these base conditions is as follows:

		Written as
Temperature (Catalyst Average)	T-T (base), °F	$T-T_B$
Pressure	P-P (base), psi	$P-P_B$
Space Velocity	LHSV/LHSV base	L/L_B
H_2 Recycle	SCFB/SCFB (base)	H/H_B

The start-of-run operating conditions were as follows:

Temperature	$T-T_B$, °F	50
Pressure	$P-P_B$, psi	0
Space Velocity	L/L_B	0.33
H_2 Recycle	H/H_B	1.33

Stability Study Discussion

At the operating conditions given above, the catalyst maintained its activity for arsenic removal for the entire 170-day run. As shown in Figure 2, the product arsenic content was maintained at less than 0.2 ppm with no increase in catalyst temperature.

While achieving the desired arsenic removal level, the feed iron content was reduced to about 0.5 ppm for the entire run with no obvious tendency to increase. The sulfur removal activity was also relatively constant giving a product value of about 0.05 wt-% for 92% removal.

A detailed, composite product analysis from late in the run is shown in Table 1. Product analyses completed at points throughout the run are given in Table 3. These data show that oxygen removal was relatively constant at about 50% whereas the nitrogen removal activity decreased from about 47% at start-of-run to about 22% at end of run. The conversion of the Conradson carbon components was relatively constant at 67%.

The overall yields for this operation are given in Table 4 and indicate a C_6 plus product in the range of 99 wt-% of fresh feed. About 580 standard cubic feet per barrel (SCFB) of hydrogen were required to accomplish this task.

At the end of the run, the catalyst was unloaded in five sections. It was free flowing and showed no signs of fouling. The used catalyst analysis given in Table 5 shows the pattern of higher to lower concentration of metal deposition from catalyst inlet to outlet. About 8.5 wt-% of arsenic was found on the chloroform-extracted catalyst removed from the top of the bed. The arsenic profile indicates that even after this six-month operation, the RCD catalyst had not reached its metals-limited capacity.

Fouling did occur three times during the course of the run. Each time, a deposit was formed at the top of the quartz chip preheater zone which caused a high pressure drop across the reactor, resulting in a "forced" shutdown. The reactor was opened and the fouled material removed and replaced. No loss in catalyst activity was observed as a result of these shutdowns.

The composition of the fouled material removed from the preheater in these three instances was quite similar. The data in Table 6 show that major constituents found on the quartz chips were carbon, hydrogen, arsenic, iron and sulfur, the remaining being trace metals. The presence of these components is indicative of more than one fouling mechanism. These data also indicate that a successful commercial unit must have special features to accommodate these foulants.

The solids present in the desalted Occidental shale oil were subjected to additional analysis. A scanning electron microscope (SEM) was used to characterize the residue trapped on 5 micron filters and the toluene insoluble solids. As shown in the photographs of Figure 3 and 4, the material ranged in size from 5 to 200 microns, with the majority of the particles in the 10-20 micon range. Residue morphologies varied. The two most prevalent forms being agglomerated particles (often comprised of dense, flat platelets) and smooth dense individual particles exhibiting rounded edges.

The elemental analysis of the ash derived from these solids is given in Table 7. Using the emission spectrographic technique, analyses were completed on both the dry ash and the wet ash (sample is digested in sulfuric acid before ashing). Based on the large difference in the iron content, which is reported as ppm of metal in the oil, some of the iron-containing compounds may have been volatilized in the dry ash procedure. There are some inconsistencies in these data which remain unexplained and deserve further analysis. It can be concluded, however, that there is a wide size range of solids and that iron, nickel, sodium, calcium, magnesium and zinc are important components.

Conclusions

Based on the results of the six-month, first-stage hydrotreating operation, it is concluded that:

1. The UOP catalyst maintained its activity and stability for arsenic and iron removal over the entire 170-day run.

2. A total of 30 wt-% metals was accumulated on the catalyst during the course of the run.

3. Product arsenic was consistently below 1 ppm and iron at 1 ppm or less.

4. The fouling which occurred in the pilot plant preheater zone must be considered in the design of a commercial unit.

5. Additional experimental work to characterize the solids and investigate the fouling mechanisms is recommended.

TABLE 1. FIRST-STAGE HYDROTREATING
OCCIDENTAL SHALE OIL

Feed and Product Comparison

	Feed	Product
API Gravity at 60°F	22.9	26.7
Specific Gravity at 60°F	0.9165	0.8944
Distillation (D-1160), °F		
IBP	376	370
5%	467	472
10%	570	508
30%	670	600
50%	712	698
70%	820	799
90%	953	940
95%	-	984
EP	-	-
% Over	87	92
Pour Point, °F	+65	+75
Viscosities		
Kinematic at 122°F, cSt	21.94	11.54
Kinematic at 210°F, cSt	5.268	3.473
Carbon, wt-%	84.85	84.85
Hydrogen, wt-%	12.27	12.63
Total Nitrogen, wt-%	1.51	1.17
Sulfur, wt-% (ppm)	0.64	(479)
Chloride, wt-ppm	< 1.0	-
BS and W, vol-%	0.2	-
Conradson Carbon, wt-%	1.36	0.45
Ash, wt-%	0.014	0.001
Heptane Insolubles, wt-%	0.34	0.01
Pentane Insolubles, wt-%	1.65	0.07
Metals by Emission (AAS), ppm		
Fe	45	(0.2)
Ni	6.7	(2.2)
V	0.42	(< 0.1)
Pb	< 0.1	
Cu	< 0.1	
Na	11	
Mo	1.6	
Arsenic, wt-ppm	27.5	< 0.1
Bromine No.	23.6	7.5
Oxygen, wt-%	0.65	0.34
Water, wt-%	0.05	

TABLE 2. PERIODIC FEEDSTOCK ANALYSIS DURING STABILITY DEMONSTRATION

Period	1	95	138	198	246	270	318
Hours on Stream	Startup	1128	1654	2376	2952	3240	3816
API at 60°F	22.7	23.3	23.2	22.5	22.6	23.0	23.2
Sp. Gr. 60/60°F	0.9176	0.9141	0.9147	0.9188	0.9182	0.9159	0.9147
Distillation (D-1160), °F							
IBP	393	378	374	370	365	400	394
5%	478	459	468	458	480	482	488
10%	509	503	502	500	508	510	522
20%	570	569	560	560	559	561	572
30%	620	629	619	610	608	619	622
40%	675	688	675	659	660	680	672
50%	722	739	731	712	714	735	722
60%	770	789	781	771	769	787	780
70%	823	835	830	830	821	834	830
80%	882	880	881	883	871	882	890
85%				910		909	959
87%					930		
88%	941						
90%		979					
% Over	88.0	90.0	85.0	85.0	87.0	85.0	90.0
% Bottoms	12.0	10.0	15.0	15.0	13.0	15.0	10.0
Bromine Number	25.6	27.0	20.0	19.8		19.8	21.1
Arsenic, ppm	14.8	15.9	12.0	16.5	13.3	24	29
Iron, ppm	59.2	60	54	58	60	62	60
Ash, ppm		0.017		0.011			

TABLE 4. SINGLE-STAGE HYDROTREATER
OCCIDENTAL SHALE OIL

Product Yields

Yields, Wt-% of Feed

H_2O	0.50
NH_3	0.50
H_2S	0.65
C_1	0.03
C_2	0.06
C_3	0.09
C_4	0.12
C_5	0.15
C_6+	98.86
Total	100.96

Chemical Hydrogen Consumption = 581 SCFB

TABLE 5. FIRST-STAGE STABILITY DEMONSTRATION RUN

Used Catalyst Analyses

	Top	Top Middle	Middle	Bottom Middle	Bottom
Arsenic, wt-%	8.42	5.58	3.35	1.58	1.31
Iron, wt-%	6.00	3.74	1.91	0.99	0.90
Carbon, wt-%	9.11	10.20	10.07	10.16	10.32
Sulfur, wt-%	6.20	6.38	5.66	5.77	5.51
Nitrogen, wt-%	0.39	0.43	0.43	0.85	0.22

TABLE 6. FIRST-STAGE STABILITY DEMONSTRATION RUN

Preheater and Plug Material

Time on Stream, Days		55		92		128	
Location		Top	Bottom	Top	Top	Top	Top
Dry Ash, wt-%		85.4	98.3	85.7		87.1	
Carbon, wt-%		10.4	0.90	10.78	0.43	10.70	1.70
Hydrogen, wt-%		-	-	1.56		1.48	
Arsenic, AAS, wt-%		-	-	-	0.11	0.56	0.43
Sulfur, wt-%		-	-	-	-	1.52	-
Method:							
Emission Spec.	Quartz* Chips	Dry Ash			Wet Ash	Dry Ash	Wet Ash
Metal, wt-%							
Fe	0.044	3.4	1.2	1.2	0.96	2.4	2.6
Ni	0.004	0.064	0.052	<0.03	<0.03	0.12	0.13
V	-	<0.003	<0.003	-	<0.03	-	<0.03
Ca	<0.03	0.068	0.032	-	<0.2	<0.3	<0.2
Mg	0.006	0.010	0.005	0.015	0.012	<0.01	0.015
Mn	0.002	0.012	0.009	0.015	0.020	0.015	0.014
Cr	0.002	0.039	0.007	0.038	0.098	0.025	0.03
Sn	-	0.010	<0.003	<0.03	<0.03	<0.03	<0.03
Cu	<0.001	0.059	0.013	0.013	<0.01	0.017	0.017
Zn	-	0.015	0.25	<0.3	<0.4	<0.4	<0.4
Ti	0.16	0.18	0.18	0.32	0.58	0.30	0.35
Pb	-	0.003	<0.001	<0.03	<0.04	<0.04	<0.04
Na	<0.05	0.45	0.025	<1.0	<1	<0.5	<1
Mo	-	0.13	0.059	0.043	<0.04	0.11	0.16
Co	0.021	0.006	0.070	0.078	0.086	0.15	0.15
Si	Major						
Al	0.46	0.49	0.58	0.37	0.60	0.38	0.45
Zr	0.006	-	-				
B	0.03	-	-				
Ba	0.006	0.007	0.005				

* This analysis is included to provide a point of reference.

TABLE 7. SOLIDS ANALYSIS

Desalted Occidental Shale Oil

Fraction Analyzed	Total Sample	Filter Cake on 5 μm Filter	Filter Cake on 10μ m Filter	Filter Cake on 25 μm Filter
Properties of Sample				
Ash Content (Dry), ppm	165			
Ash ASTM D-482, wt-%	0.015			
Toluene Insoluble, UOP 614, wt-%	0.01			
Stability, ASTM D-1661				
Thimble Rating				
Unwashed	stable			
Unwiped, Washed	stable			
Wiped, Washed	stable			
Stability, UOP 174	stable			
BS&W before O_2	<0.05			
BS&W after O_2	<0.05			
Toluene Insoluble on 5 μm Filter, wt-%	0.005			
Toluene Insoluble on 10 μm Filter, wt-%	0.005			
Toluene Insoluble on 25 μm Filter, wt-%	0.003			
Emission Spectrographic Analysis of Ash				
Elements — Reported as ppm metal in the oil		**	**	**
Fe	7.4	9.8	23.0	8.3
Ni	18	0.02	0.07	0.04
V	0.84	0.02	0.02	0.02
Mn	0.18	0.02	0.03	0.01
Cr	0.31	0.02	0.03	0.01
Pb	0.14	0.09	0.15	0.07
Sn	0.32	0.21	0.22	0.14
Cu	4.3	0.05	0.07	0.03
Zn	6.3	0.53	0.61	0.31
Ti	0.50			
Al	Diluent	0.27	0.40	0.13
Mg	2.1	0.50	0.23	0.09
Ca	5.5	1.1	2.6	0.33
Na	8.4	3.1	6.9	1.9
Mo	3.3	0.02	0.03	0.01
Si	2.6			
Co	4.8			
B*	0.5			
Emission Spectrographic Analysis of Wet Ash				
Elements — Reported as ppm metal in the oil				
Fe	58			
Ni	12			
V	0.68			
Pb	<0.05			
Cu	0.19			
Na	9.9			
Mo	4.0			

* Est. only. ** Semi-Quantitative/Samples reacted with quartz beakers.

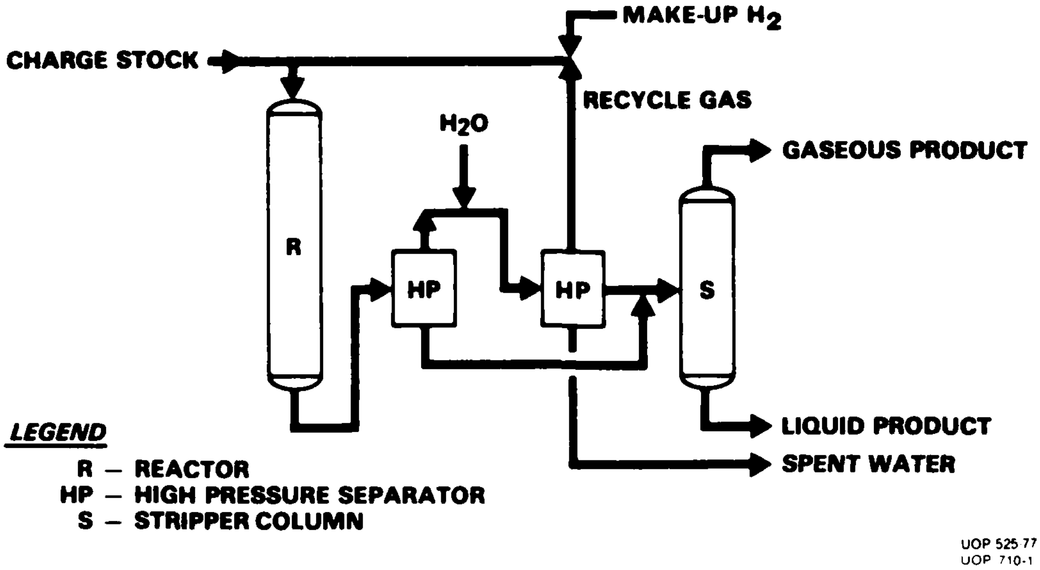


FIGURE 1

FIRST STAGE HYDROTREATING PILOT PLANT

SCHEMATIC FLOW DIAGRAM

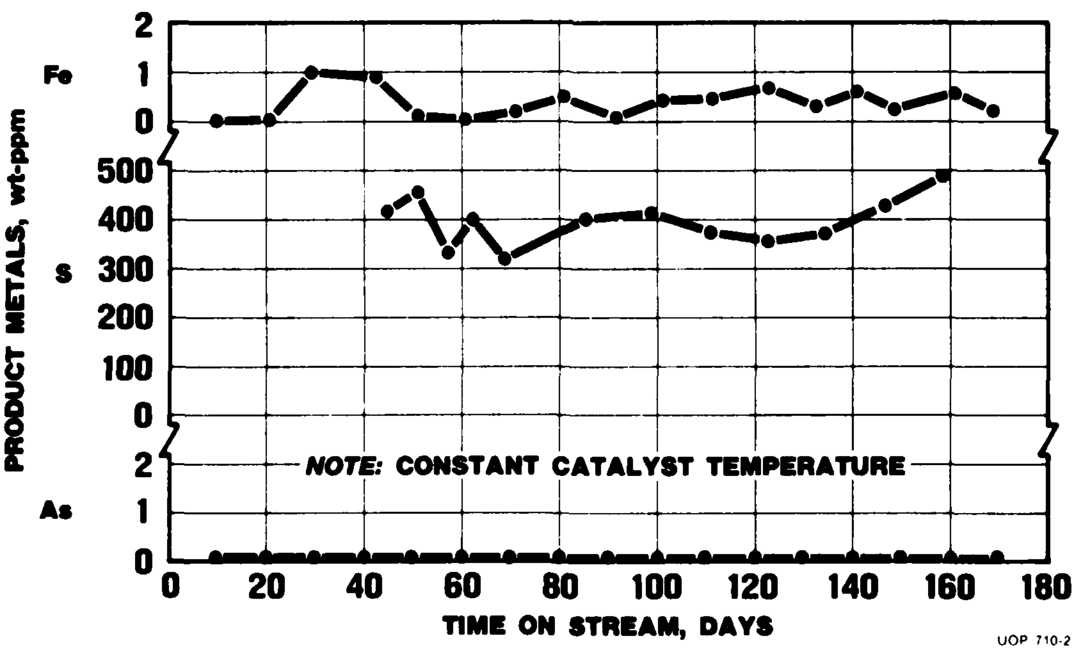
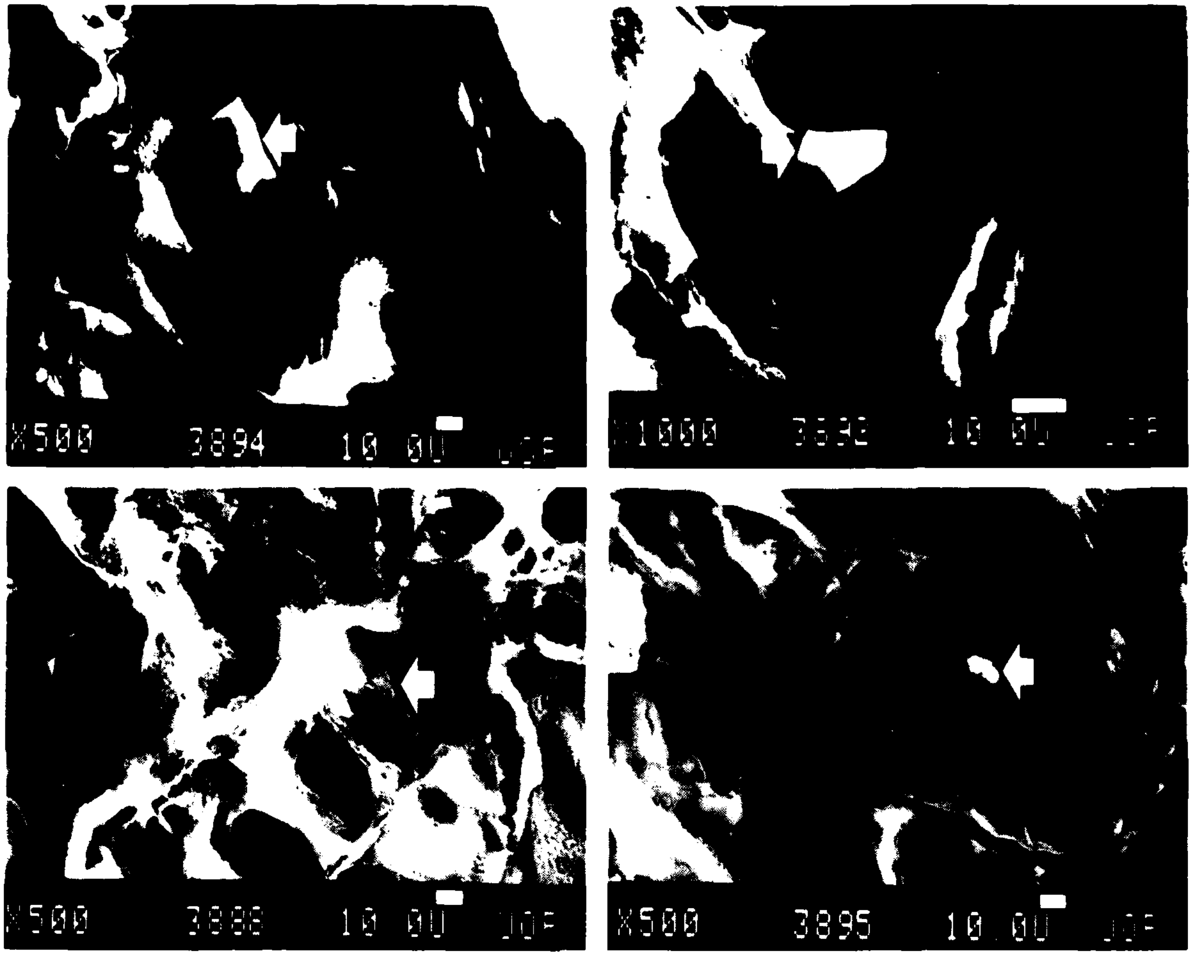


FIGURE 2

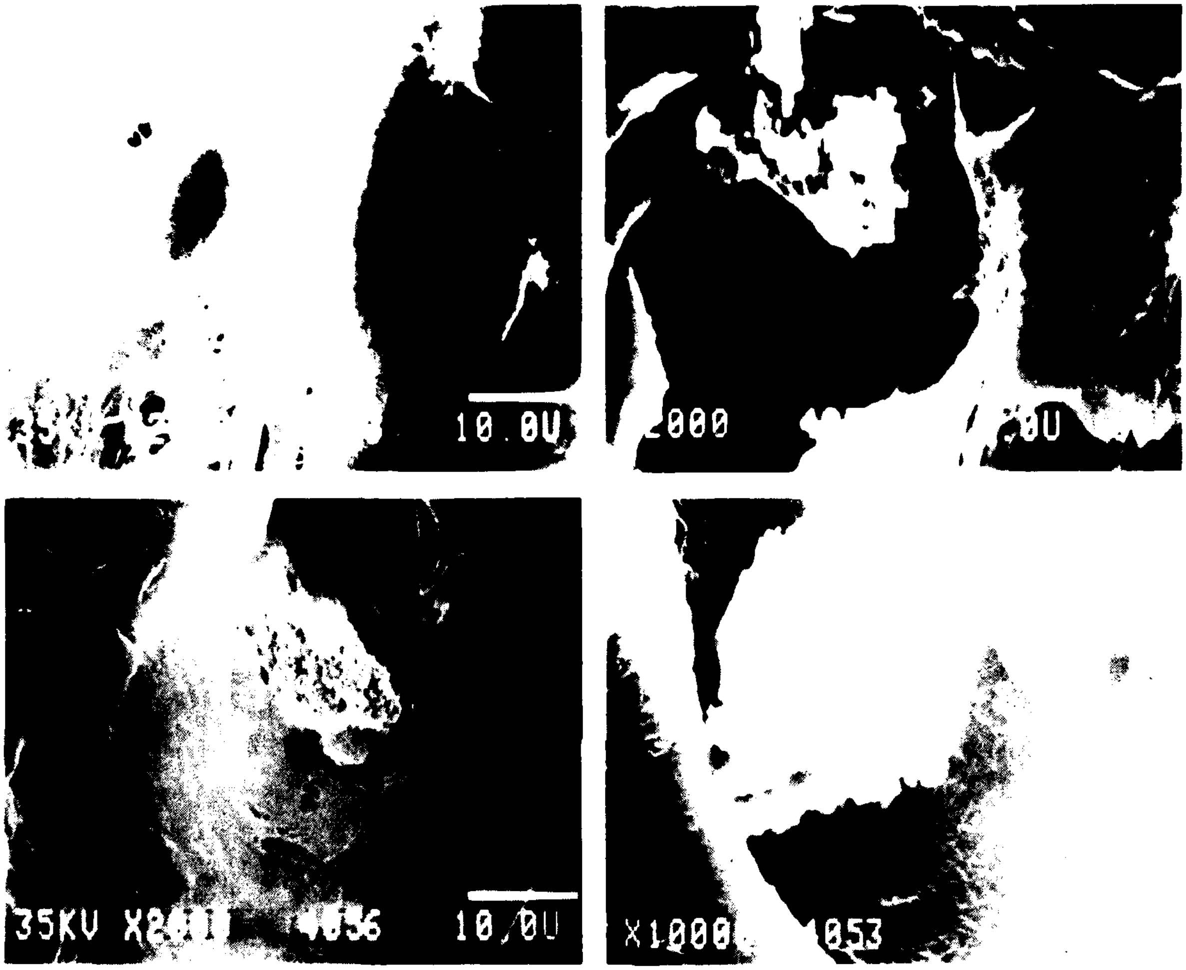
FIRST STAGE HYDROTREATING CATALYST STABILITY DEMONSTRATION



UOP 734-23

FIGURE 3

SCANNING ELECTRON MICROSCOPE ANALYSIS OF OCCIDENTAL SHALE OIL RESIDUE



UOP 734-24

FIGURE 4

SCANNING ELECTRON MICROSCOPE ANALYSIS OF OCCIDENTAL SHALE OIL TOLUENE INSOLUBLES

SECTION III

HYDROCRACKING

As part of the Phase III pilot plant program, three hydrocracking studies were completed: preparation of 5-gallon samples of jet and diesel fuels, determination of catalyst stability in the parallel-flow scheme, and investigation of sulfur addition to the hydrocracker feedstock. The data developed from these studies were also used to confirm the refinery design and provide other information needed in the economic evaluation program of Phase IV.

Pilot Plant Description

The pilot plant used in the hydrocracking operation embodies the essential features of a commercial unit. Fresh feed, recycle liquid, recycle gas and makeup hydrogen are charged to the reactor section. Trickle-bed reactors containing 25-200 mL of catalyst were employed. Gas is recycled from the high pressure separator back to the reactor section. The reactor liquid effluent is charged to a series of separators including a fractionator and debutanizer to produce liquid product and a recycle liquid stream. In the pilot plant operations, reactor temperatures were adjusted to achieve 100% conversion of the feed to products. During these operations, no fractionator bottoms product was withdrawn as a net product.

The DCC catalyst used in this study is a proprietary material which has seen wide commercial operation. This is the same catalyst which was used successfully in the Phase II hydrocracking programs.

Feedstock

The hydrocracker feedstock is a second-stage hydrotreated Occidental shale oil, whose properties are shown in Table 8. This stock was produced by first hydrotreating the raw shale oil at relatively mild conditions to remove the contaminants and stabilize the material, and then hydrotreating the first-stage product at relatively severe conditions to reduce the high levels of impurities, such as nitrogen and oxygen, that were still present. The measured nitrogen content of the material was 780 ppm. The hydrocracker feed sulfur content was 139 ppm, the oxygen content 545 ppm, and the Bromine number 1.1.

Operating Conditions

The operating conditions used in the production of the fuel samples were in the range of those commercially practiced, and for this report, are presented relative to the conditions appropriate for converting a typical Arabian vacuum gas oil. The nomenclature adopted is as follows:

		Written as
Temperature (Catalyst Average)	T-T (base), °F	$T-T_B$
Pressure	P-P (base), psi	$P-P_B$
Space Velocity	LHSV/LHSV (base)	L/L_B
Combined Feed Ratio	CFR/CFR (base)	C/C_B
H_2 Recycle	SCFB/SCFB base	H/H_B

The conditions in the two operations, Runs 1 and 2, were varied depending on the type of fuel being produced. Run 1 was designed to produce the jet fuel samples. The latter portion of the run was used to establish operating conditions and procedures for the diesel fuel production and the stability demonstration, in Run 2.

Run 2 proceeded initially in the JP-8 mode to obtain the base activity-conversion level. This was followed by the more severe diesel fuel production mode. The final processing was again in the JP-8 mode to obtain the final activity-conversion level and the catalyst deactivation rate.

Run	1			2			
Type of Fuel	JP-8	JP-4	Diesel	JP-8	Diesel	JP-8	JP-8
Hours on Stream	70-360	360-610	610-860	0-150	150-460	460-780	780-1293
Temperatures, $(T-T_B)$, °F	-54	-50	-44	-53	-49	-43	-45
Pressure, $(P-P_B)$, psig	-150						
Space Velocity, (L/L_B)	1.4	1.4	2.0	1.4	2.0	1.4	1.4
CFR, (C/C_B)	1.0	1.0	0.8	1.0	0.8	1.0	1.0
H_2 Recycle, (H/H_B)	1.4						

Sample Production

Representative product yield distributions obtained when hydrocracking the hydrotreated Occidental shale oil to JP-4 and JP-8 fuels are given in Table 9. The JP-4 yield was better than 84 wt-% and required 1029 SCFB of hydrogen. The JP-4 volume yield amounted to about 93 vol-% of hydrocracker feed. The equivalent values for JP-8 are 75 wt-% yield (80 vol-%) with 921 SCFB hydrogen consumption. Both of these yield patterns show the excellent selectivity of the parallel-flow scheme for jet fuel production.

More detailed product distributions for the JP-4 and JP-8 cases are given in Tables 10 and 11, respectively. Both of these analyses are from single test periods and differ slightly from the average values given in Table 9. Included with the more detailed light ends yields are the iso- and normal-paraffin breakdown for the butanes and pentanes. About 60 wt-% of the butanes and 67 wt-% of the pentanes are in the more valuable non-normal configuration.

The UOP inspections of the JP-4 jet fuel sample are shown in Table 12 along with the USAF specifications. With the exception of the slightly high 50 and 90% points of the distillation and the conductivity, this product meets all U.S. military specifications and should be environmentally acceptable in view of the low nitrogen and sulfur contents. With only 8.7 vol-% aromatics reported (25.0 vol-% is the maximum specification), the Smoke Point exceeds the minimum acceptable level of 20 by 8.5. The net combustion value is some 300 Btu/lb higher than required and is a reflection of the high hydrogen content obtained in the parallel-flow hydrocracking operation.

Inspections of the JP-8 jet fuel produced are shown in Table 13, along with the USAF specifications. These inspections meet all of the U.S. military specifications except for Freeze Point (-54°F vs. -58°F) and conductivity. These can be easily met by slightly lowering the end point and including an additive, respectively. This higher end point fuel, 552°F vs. 517°F for the JP-4, contains 9.7 vol-% aromatics and gave a Smoke Point of 27.2 (minimum specification is 25). The combustion value is 200 Btu/lb higher than required and again shows the high hydrogeration capability of the parallel-flow hydrocracking operation.

An analysis of the C_5-C_6 fraction obtained during the JP-8 production run is given in Table 14. This material is highly isomerized and contains less than 1 wt-% benzene. The clear Research octane number of 70.6 increased to 87.7 with the addition of 3 cc TEL per gallon.

A detailed analysis of the C_7-232°F naphtha yielded during the JP-8 production run is given in Table 15. This highly saturated material contains 96.8 vol-% paraffins plus naphthenes and has a clear Research octane number of 60.2. After treatment to remove the small quantity of sulfur remaining, this naphtha represents a good feedstock for further upgrading by catalytic reforming to produce both a high octane blending component and hydrogen for the shale oil hydrotreating operations. The catalytic reforming of this material is discussed later in this report.

The product distributions for hydrocracking the hydrotreated Occidental shale oil to DF-2 and DFM are shown in Table 16. The yields of 98.6 wt-% and 96.2 wt-% were achieved for DF-2 and DFM, respectively. Both fuels were produced with the same end point and, therefore, the yield difference results from adjusting the amount of C_5-C_6 material in the product to meet the specified flash points. As noted in the jet fuel production cases, the parallel-flow hydrocracking scheme showed excellent selectivity for converting the hydrotreated shale oil into these distillate fuels. The chemical hydrogen consumption was 800 SCFB for both the DF-2 and DFM cases.

A more detailed product distribution obtained in a single test period in the diesel fuel production mode is given in Table 17. The C_4- yield in this operating mode is only about one-third that observed in the more severe jet fuel operations. The extent of butane and pentane isomerization is about the same: 60% iso in the total butane and 67% iso in the total pentane.

Inspections of the DF-2 and DFM samples, together with the U.S. military specifications, are shown in Tables 18 and 19, respectively. These inspections show that the diesel fuels met all specifications. Both samples had Cetane numbers greater than 55 and very low sulfur contents of about 1 ppm. Both diesel fuels show excellent stability and should be environmentally acceptable. In addition, their low acid numbers, copper strip corrosions, sediments, particulates, excellent stabilities and high cetane numbers should pose no problem for storage and use in engines.

Catalyst Stability Demonstration

A second objective in the Phase III hydrocracking program was to make an extended catalyst stability study to provide information regarding longer term effects of processing shale oil in the proposed UOP turbine fuels refinery and to assess the advantage of parallel-flow over single-stage hydrocracking in terms of catalyst stability.

As indicated previously, the stability run was made in the same hydrocracking operation used for the sample production. After checking the plant operation in the JP-8 mode for 150 hours, and then producing the diesel samples, the plant was switched back to the JP-8 mode, and the operation continued for a period of 1200 hours to measure the catalyst deactivation.

The deactivation was measured by the increase in reactor temperature per unit of operating time required to maintain constant conversion to a specified product end point. In this case, the end point was that required to make JP-8 jet fuel. Results of the run are shown in Figure 5. The rate of deactivation is slightly lower than was reported for a similar operation over a shorter period of time in the Phase II program and as shown in the Phase II report, much improved over the expected result for the single-stage operation.

During the catalyst stability demonstration (Run 2), and at the end of Run 1, plugging of the reactor preheater was observed. Elemental analyses of the material recovered from the inert, granular material (quartz chips) are given in Table 20. Relatively high concentrations of iron, nickel and chromium are found. Analyses of the carbonaceous material found at the same time periods on a filter in the fresh feed line, as given in Table 21, indicate the presence of high molecular weight, heteroatomic materials. The presence of these materials in the hydrotreated feedstock and their subsequent fouling of the reactor preheater are believed due to oxidation and degradation as a result of handling and storing this material during a 9-month period.

Sulfur Addition

In the Phase II hydrocracking program, it had been observed that the addition of sulfur to the relatively sulfur-free hydrocracker feedstock improved the activity of the catalyst. With the feedstock containing less than 3 ppm sulfur, it was suspected that this was insufficient to maintain the catalyst in its activated (sulfided) state.

After the period in which the stability of the catalyst was demonstrated, 10,000 ppm of sulfur as ditertiary-butyl disulfide was added to the feed. As before, the catalyst temperature required to maintain conversion was reduced by about 10°F. The presence of plant operating problems in the fractionation section forced this study to be discontinued before a definitive response could be determined.

Conclusions

Based on the results of these hydrocracking operations, it was concluded that:

1. The parallel-flow hydrocracker can produce military turbine fuels and diesel fuel in excellent yields.

2. These fuels not only meet, but exceed, military specifications in many areas.

3. The parallel-flow hydrocracker offers improved catalyst stability when compared with conventional single-stage hydrocracking.

TABLE 8. HYDROCRACKING FEEDSTOCK

Occidental Shale Oil

API Gravity at 60°F	32.0
Sp. Gr., 60/60°F	0.8654
Distillation (D-1160), vol-%	
IBP, °F	390
5%	469
10%	495
30%	581
50%	663
70%	760
90%	898
95%	958
EP, °F	988
% Over	97.0
Carbon, wt-%	86.99
Hydrogen, wt-%	13.41
Nitrogen, ppm	780
Sulfur, ppm	139
Pentane Insolubles, wt-%	0.12
Heptane Insolubles, wt-%	0.05
Conradson Carbon, wt-%	0.09
Ash, wt-%	0.001
Bromine Number	1.1
BS & W, wt-%	0.4
Toluene Insolubles, wt-%	0.01
Oxygen, ppm	545
Molecular Weight	305

Boiling Pt. GC, Wt-%	
% Over	Temp., °F
IBP	241
5	361
10	421
15	463
20	495
25	519
30	545
35	571
40	592
45	615
50	640
55	666
60	692
65	718
70	747
75	776
80	804
85	832
90	872
95	931
FBP	1100

TABLE 9. HYDROCRACKER PRODUCT DISTRIBUTIONS

Hydrotreated Occidental Shale Oil Feed

Product Desired	JP-8	JP-4
Wt-%		
Fresh Feed	100.00	100.00
H_2 Consumption, wt-%	1.61	1.80
H_2 Consumption, SCFB	921	1029
NH_3	0.08	0.08
H_2S	0.01	0.01
C_1-C_3	1.50	1.88
C_4	3.73	4.80
C_5-C_6	9.29	11.03
C_7-250°F	11.75	JP-4 { 12.18
250-EP	JP-8 75.25*	JP-4 { 71.82**
Total	101.61	101.80
Vol-%		
Fresh Feed	100.00	100.00
C_4	5.78	7.43
C_5-C_6	12.62	14.75
C_7-250 °F	13.76	JP-4 { 14.31
250-EP	JP-8 80.40*	JP-4 { 78.68**
Total	112.56	115.17

* Product EP ∿550°F
** Product EP ∿520°F

TABLE 10. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

JP-4 Product Distribution

	Yield, Wt-%	Yield, Vol-%	Gas Yield, SCF/BBL
Hydrogen	0.23		
H_2S	0.01		
NH_3	0.16		
Methane	0.24		16.4
Ethane	0.25		9.1
Propane	1.39		34.2
Isobutane	2.83	4.44	53.0
n-Butane	1.97	2.98	36.9
Isopentane	3.29	4.63	
n-Pentane	1.70	2.37	
Hexane	6.03	7.74	
C_7-250°F Fraction	12.17	14.29	
250-EP Fraction	71.74	78.59	
Total	102.01	115.03	149.7
Subtotals			
C_1-C_4 Fraction	6.68		149.7
C_5-C_6 Fraction	11.02	14.73	
C_7-250°F Fraction	12.17	14.29	
250-EP Fraction	71.74	78.59	
C_5+ Fraction	94.93	107.61	
Percent Iso in			
Butane	58.94		
Pentane	65.85		

TABLE 11. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

JP-8 Product Distribution

	Yield, Wt-%	Yield, Vol-%	Gas Yield, SCF/BBL
Hydrogen	0.22		
H_2S	0.01		
NH_3	0.16		
Methane	0.18		12.0
Ethane	0.18		6.5
Propane	1.09		26.9
Isobutane	2.42	3.81	45.4
n-Butane	1.52	2.29	28.4
Isopentane	3.02	4.26	
n-Pentane	1.42	1.97	
Hexane	4.98	6.60	
C_7-232°F Fraction	7.73	8.71	
232-EP Fraction	78.90	85.65	
Total	101.83	113.28	119.2
Subtotals			
C_1-C_4 Fraction	5.39		119.2
C_5-C_6 Fraction	9.42	12.83	
C_7-232°F Fraction	7.73	8.71	
232-EP Fraction	78.90	85.65	
C_5+ Fraction	96.05	107.18	
Percent Iso in			
Butane	61.5		
Pentane	68.1		

TABLE 12. JP-4 JET FUEL

	USAF Specs.	Production Sample
API Gravity at 60°F	45-57	49.6
Sp. Gr. 60/60°F		0.7813
Distillation (D-86), vol-%		
IBP, °F	report	202
5%		236
10%	report	255
20%	293	288
30%		321
40%		354
50%	374	386
60%		414
70%		437
80%		456
90%	473 max.	478
95%		495
EP, °F	518 max.	517
Freeze Point, °F	-72 max.	Below -70°F
Smoke Point	20 min.	28.5
Vapor Pressure, 38°C, psi	2-3 max.	0.8
Viscosity -20°C, cSt		3.207
Acid No., mg KOH/mg	0.015 max.	0.012
Copper Strip Corrosion	1B max.	1A
Coulometric Sulfur, ppm	0.4 wt-% max.	737
Mercaptan Sulfur, wt-%	0.001 max.	0.0001
Coulometric N, ppm		0.37
Carbon, wt-%		84.23
Hydrogen, wt-%	13.6 min.	14.39
FIA, vol-%		
P + N		91.3
O	5.0 max.	-
A	25.0 max.	8.7
Combustion, Btu/lb	18,400 min.	18,700
Existent Gum, Unwashed/Washed, mg per 100 mL	7 max.	7.8/4.0
Naphthalenes, UV wt-%		0.28
Conductivity	50-300	1 $\bar{p}$ S/M
Water Separation D-1094		
Interface Rating	1B max.	1B
Separation Rating	1 max.	1
Demulsification		No Emulsion Oil Layer Clear No Scum

JFTOT

Temp., °C	Min.	ΔP mm Hg	TDR Spun	ASTM Code
260	150	1.5	1.5	0

TABLE 13. JP-8 JET FUEL

Production Sample

	USAF Specs.	
API Gravity at 60°F	37-51	46.0
Sp. Gr. 60/60 F	0.775-0.840	0.7972
Distillation (D-86), vol-%		
IBP, °F	report	288
5%		308
10%	401 max.	321
20%		352
30%		384
40%		412
50%		434
60%		455
70%		474
80%		492
90%		512
95%		525
EP, °F	572 max.	552
% Over		99.0
Smoke Point	25 min.	27.2
Freeze Point, °F	-58 max.	-54
Flash Point, °F	100 min.	100
Viscosity -20°C, cSt	8.0 max.	5.670
Acid No., mg KOH/gm	0.015 max.	0.01
Coulometric Sulfur, ppm	0.4 wt-% max.	499
Mercaptan Sulfur, wt-%	0.001 max.	0.00048
Carbon, wt-%		84.63
Hydrogen, wt-%	13.6 min.	14.14
FIA, vol-%		
P + N		90.7
O	5.0 max.	-
A	25.0 max.	9.3
Combustion, Btu/lb	18,400 min.	18,600
Copper Strip Corrosion	1B max.	1A
Coulometric N, ppm		0.7
Existent Gum, Unwashed/Washed, mg per 100 mL	7 max.	4.1
Naphthalenes, UV wt-%	3 max.	0.35
Conductivity	50-300	4 $\bar{p}$ S/M
Water Separation D-1094		
Interface Rating	1B max.	1
Separation Rating	2 max.	1

JFTOT

Temp., °C	Min.	ΔP mm Hg	TDR Spun	ASTM Code
260	150	0	1.0	0

TABLE 14. C_5-C_6 FRACTION FROM JP-8 JET FUEL

API 60°F	77.2
Sp. Gr., 60/60°F	0.6780
Distillation (D-86), vol-%	
IBP, °F	124
5%	134
10%	136
20%	140
30%	141
40%	144
50%	146
60%	148
70%	150
80%	152
90%	156
95%	161
EP, °F	220
% Over	99.0
Coulometric S, ppm	1.0
Nitrogen, ppm (Chem Lum)	0.83
RON Clear	70.6
Leaded (3 cc TEL/gal)	87.7

Composition by GC, Wt-%	
i-C_4	0.1
n-C_4	0.2
i-C_5	5.8
n-C_5	6.3
2, 2 DMB	0.4
CP	0.6
2,3 DMB	2.7
2 MP	22.3
3 MP	15.4
n-C_6	22.1
MCP	17.2
CH	2.1
Bz	0.9
C_7+	3.9

TABLE 15. C_7-232°F FRACTION FROM JP-8 JET FUEL

API at 60°F	64.0
Sp. Gr., 60/60°F	0.7238
Distillation (D-86), vol-%	
IBP, °F	194
5%	197
10%	198
20%	199
30%	201
40%	202
50%	203
60%	205
70%	207
80%	209
90%	216
95%	222
* EP, °F	278
% Over	99.0
Coulometric S, ppm	17.1
Nitrogen, ppm (Chem Lum)	0.40
Carbon, wt-%	83.76
Hydrogen, wt-%	16.00
FIA, vol-%	
P + N	96.8
O	-
A	3.2
RON Clear	60.2
RON Leaded (3 cc TEL/gal)	82.2

	GC, Wt-%
Aromatics	
Toluene	3.5
m-Xylene	0.1
Total	3.6
Paraffins/Naphthenes	
C_6 Paraffins	2.83
C_6 Cyclics	2.74
C_7 Paraffins	44.38
C_7 Cyclics	28.34
C_8 Paraffins	10.43
C_8 Cyclics	8.39
C_9 Paraffins	.19
C_9 Cyclics	0.10
	97.40

* Dry Point = 232°F

TABLE 16. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL TO DF-2 AND DFM DIESEL FUELS

	Feed	DF-2	DFM
Product Distribution, wt-%			
H_2S		0.01	0.01
NH_3		0.10	0.10
H_2O		0.06	0.06
C_4 minus		1.68	1.68
C_5 and/or C_6		1.00	2.36
Flash Point* to EP Diesel Fuel	44.0	98.55	96.19
Total		101.40	101.40
* Flash Point, °F		133	140
Hydrogen Consumption, SCF/B		800	

TABLE 17. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

Diesel Product Distribution

	Yield, Wt-%	Yield, Vol-%	Gas Yield, SCF/BBL
Hydrogen	0.13		
H_2S	0.01		
NH_3	0.10		
Methane	0.13		8.9
Ethane	0.11		4.0
Propane	0.38		9.3
Isobutane	0.68	1.07	12.7
n-Butane	0.48	0.72	8.9
Isopentane	0.82	1.16	
n-Pentane	0.40	0.56	
Hexane	1.30	1.72	
C_7-183°F Fraction	0.19	0.16	
183-EP Fraction	96.77	100.78	
Total	101.51	106.17	43.8
Subtotals			
C_1-C_4 Fraction	1.77		43.8
C_5-C_6 Fraction	2.53	3.34	
C_7-183°F Fraction	0.19	0.16	
183-EP Fraction	96.77	100.78	
C_5+ Fraction	99.49	104.28	
Percent Iso in			
Butane	58.8		
Pentane	67.05		

TABLE 18. DIESEL FUEL DF-2

Production Sample

	USAF Specs.		
API Gravity at 60°F	32.9-41	38.8	
Sp. Gr. 60/60°F		0.8309	
Distillation (D-86), vol-%			
IBP, °F		320	
5%		362	
10%		400	
20%		452	
30%		486	
40%		513	
50%	report	542	
60%		568	
70%		593	
80%		618	
90%	675 max.	646	
95%		664	
EP, °F	700 max.	678	
% Over		98.5	
Flash Point, °F	133 min.	134	
Cloud Point, °F	report	32	
Pour Point, °F		5	
Aniline Point, °F		173.1	
Viscosity 100°F, cSt	1.8-9.5	3.367	
D-1500 Color	report	<2	
Acid No., mg KOH/gm	0.10 max.	0.018	
Copper Strip Corrosion, 100°C	1 max.	1A	
Coulometric Sulfur, ppm	0.70 wt-% max.	1.2	
Cetane Number	45 min.	55.1	
Water and Sediment, D-2709, wt-%	0.01 max.	0.005	
Demulsification, 25°C		No Emulsion Oil Layer Clear	
Particulate Cont. D-2276, mg/L	8 max.	8	
Carbon Residue on 10% Botts, D-524, wt-%	0.2 max.	0.11	
Ash, wt-%	0.02 max.	0.001	
Stability D-2274, mg/100 mL			
Adherent Gum	1.5 max.	0.45	Total 0.8
Sediment		0.35	

TABLE 19. DIESEL FUEL MARINE DFM

Production Sample

	USAF Specs.		
API Gravity at 60°F	report	38.7	
Sp. Gr. 60/60°F		0.8314	
Distillation (D-86), vol-%			
IBP, °F		348	
5%		376	
10%		420	
20%		465	
30%		498	
40%		525	
50%	report	550	
60%		575	
70%		598	
80%		624	
90%	675 max.	650	
95%		672	
EP, °F	725 max.	680	
% Over		99.0	
Flash Point, °F	140 min.	144	
Cloud Point, °F	30 max.	28	
Pour Point, °F	20 max.	5	
Aniline Point, °F	report	173.1	
Viscosity 100°F, cSt	1.7-4.3	3.444	
D-1500 Color	3 max.	<3	
Acid No., mg KOH/gm	0.30 max.	0.021	
Copper Strip Corrosion, 100°C	1 max.	1A	
Coulometric Sulfur, ppm	1.0 wt-% max.	1.9	
Cetane Number	45 min.	55.3	
Water and Sediment, D-2709, wt-%		<0.005	
Demulsification, 25°C, minutes	10 max.	No Emulsion Oil Layer Clear	
Particulate Cont. D-2276, mg/L		5	
Carbon Residue on 10% Botts, D-524, wt-%	0.2 max.	0.11	
Ash, wt-%	0.005 max.	<0.001	
Stability D-2274, mg/100 mL			
Adherent Gum	2.0 max.	0.3	Total 0.7
Sediment		0.3	

TABLE 20. PREHEATER PLUG ANALYSES

Run 2

			End of Run
Time on Stream, hours		783	1703
Plug Number		1	2
Solids, wt-%	Quartz Chips	96.2	92.5
Emission, wt-ppm			
Fe	440	260	870
Ni	40	30	70
V	-	30	60
Ca	300	280	290
Mg	60	10	80
Mn	20	20	30
Cr	20	-	-
Sn	-	-	-
Cu	10	50	140
Zn	-	-	40
Ti	1600	1500	1900
Pb	-	-	-
Na	500	1000	1000
Mo	-	30	30
Co	210	-	-
Si	Major	Major	Major
Al	4600	2300	5300
Ba	60	30	60
Sr	-	-	-
Zr	60	240	310
B	300	800	110
Carbon, wt-%		53.67	6.90
Sulfur, wt-%		5.12	

TABLE 21. FRESH FEED FILTER CAKES

Run 2

Time on Stream, hours	783		End of Run 1703
Molecular Weight	392		380
ASTM Ash, wt-%	0.22		0.50
Con. Carbon, wt-%	9.43		12.3
C_5 Insol., wt-%	21.3		23.5
C_7 Insol., wt-%	19.1		22.8
Toluene Insol., wt-%	6.12		7.12
Bromine Number	6.6	(Modified Method)	4.6
Carbon, wt-%	84.44		84.85
Hydrogen, wt-%	12.45		12.77
Sulfur, wt-%	1.25		1.70
Nitrogen, wt-%	0.52		0.524
Oxygen, wt-%	1.64		0.88 ± 0.06
Emission, wt-ppm			
Fe	780		54
Ni	9		4.8
V	86		13
Ca	180		6.9
Mg	0.11		1.4
Mn	25		1.6
Cr	5.0		0.51
Sn	33		0.99
Cu	61		2.5
Zn	100		10.6
Ti	9.7		6.7
Pb	7.5		0.78
Na	78		9.2
Mo	8.9		0.85
Co	2.2		-
Si	230		Diluent
Al	Diluent		3.4
B	50		0.78
Ba	1.7		1.6
Sr	--		-
Zr	0.36		-
Ash	2,780		709
Melting Point, °F			206*

* Heavy material left on tip of thermometer which will not melt.

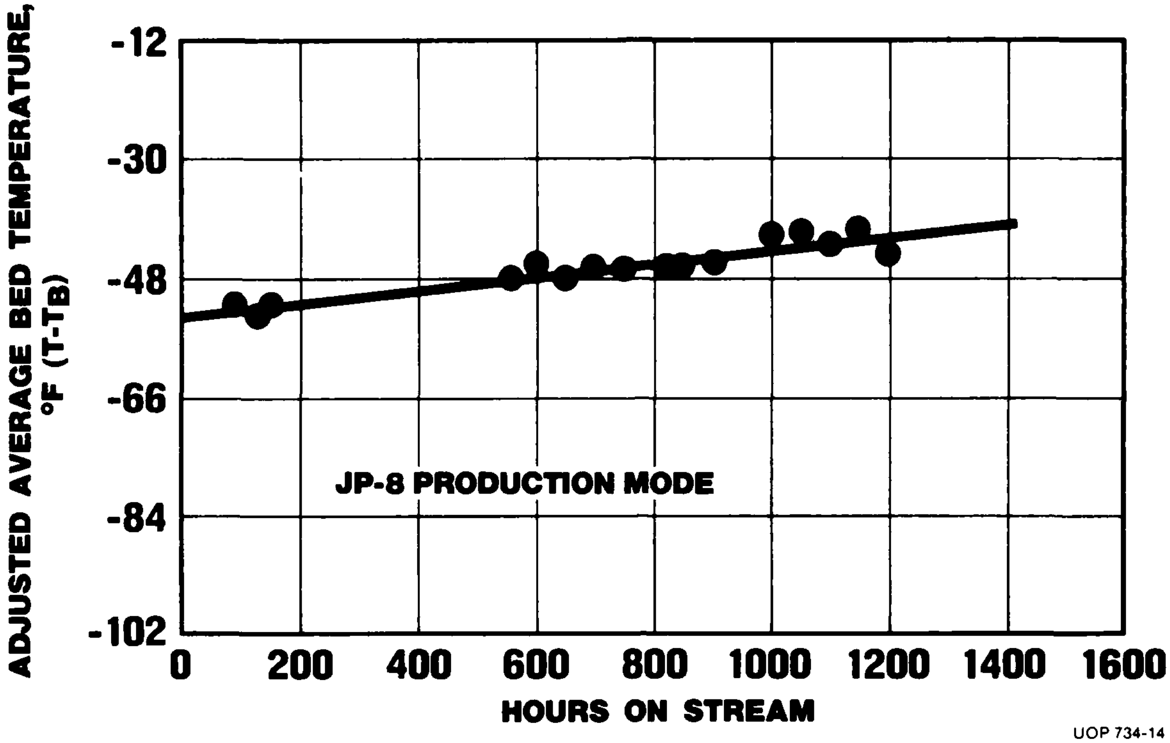


FIGURE 5

PARALLEL — FLOW HYDROCRACKING CATALYST ACTIVITY AND STABILITY

SECTION IV

PLATFORMING OF A C_7-300°F SHALE OIL NAPHTHA

As part of the Phase III program, a narrow boiling naphtha cut from the hydrocracking operations was catalytically reformed to obtain basic information on yields and octane, and to compare this shale-derived naphtha with petroleum stocks.

Shale oils generally have narrower boiling ranges, from about 400° to 1000°F, and contain less naphtha as compared to petroleum crudes. With this boiling range, shale oils readily lend themselves to production of diesel and jet fuels. However, high yields of good quality gasoline can be produced from shale oil depending on the refinery configuration.

The UOP Platforming® process is a proprietary catalytic reforming process developed by UOP. It can be used to produce an excellent petrochemical feed for BTX recovery, or produce a high octane blending component for gasoline production. A valuable by-product of these operations is the production of hydrogen. In this instance, Platforming was used to investigate the shale oil naphtha as a potential source of special motor fuel.

Pilot Plant Description

A schematic diagram of the pilot plant used for this operation is shown in Figure 6. Fresh feed with recycle hydrogen is fed over the catalyst. The reactor effluent is condensed and the gas and liquid separated. The gas is recycled back to the reactor while the propane and heavier liquid is debutanized. The hydrogen produced in the process is removed continuously through a pressure regulator, measured and analyzed. The debutanized C_5+ product is similarly weighed and analyzed.

Present commercial Platforming catalysts comprise extruded or spherical alumina promoted with Group IV, VII and VIII metals. A commercially proven UOP Platforming catalyst designated Rx-320 was employed in this study.

Feedstock

The Platforming naphtha feed was prepared by fractionating the hydrocracked product from the Phase II operations in two steps to remove the 300°F+ heavies and the C_6- light front end to yield essentially 10 gallons of a C_7 to 300°F product. Inspections of this product are shown in Table 22.

This 58.5 °API gravity naphtha contained about 91 vol-% paraffins plus naphthenes, 1 vol-% olefins and 8 vol-% aromatics. The clear Research octane number was about 55. The nitrogen content was acceptable at <0.1 ppm, but the 110 ppm sulfur content and the 1% olefins were outside the normal specifications for Platformer feedstock. The high sulfur content was a result of the sulfur addition experiments in the hydrocracking program.

A mild hydrotreating operation was used to prepare the Platformer® feed. The operating conditions were typical of those required to hydrotreat a petroleum-derived naphtha. Following this hydrotreating step, the total product was fractionated to reduce the 95% and end points to about 255° and 298°F, respectively. The analysis of the Platformer feed is shown in Table 23. The sulfur and nitrogen contents are well below the levels required for current Platforming operations. The aromatics content has been reduced to about 5 vol-%. A detailed GC analysis of this material is given in Table 24.

Operating Conditions

Process conditions used in this study are comparable to those commercially employed for reforming petroleum naphtha. The base conditions selected for reference represent those employed commercially for

UOP's "State-of-the-Art" design of Continuous Platforming units. The nomenclature adopted to relate the actual operating conditions to these base conditions are as follows:

		Written as
Temperature	T-T (base), °C	$T-T_B$
Pressure	P-P (base), psi	$P-P_B$
Space Velocity	LHSV/LHSV (base)	L/L_B
Hydrogen/Feed Ratio	$\frac{H_2/\text{Feed}}{H_2/\text{Feed (base)}}$	H/H_B

This operation covered a range of temperatures from 70°F below to 20°F above the base temperature to obtain a yield-octane relation for this feed. The other operating conditions were:

Pressure	$P-P_B$, psi	0
Space Velocity	L/L_B	2
Hydrogen/Feed Ratio	H/H_B	2.5

Yield-Octane Study

The Platformer product analyses with Research Octane numbers from 90 to 104 are given in Table 25. Product aromatic contents range from about 50 vol-% at 90 RONC to about 79 vol-% at 104 RONC. The product octanes responded very well to lead addition. There is an 8.5 octane increase in the product from the lowest octane operation to a 5.0 increase at the highest octane.

The product yield data are related to octane level in Figures 7, 8 and 9. The C_5 plus liquid yield varied linearly from 85 vol-% at 89 RONC to 70 vol-% at 104 RONC. At the highest operating severity there is an indication that the hydrogen yield (Figure 8) is leveling off.

Overall, the data show this shale oil naphtha cut to be an excellent Platformer feedstock that will give yields comparable to petroleum derived feeds when reformed to octanes ranging from 90 to 104 RONC.

Special Gasoline Preparation

The individual products from this Platforming operation were blended to make a larger sample which was subsequently used to make a Special Grade, Class B volatility, gasoline. The analyses of this sample, as reported in Table 26, show a 47.2 °API gravity material having a Research octane number of 95.5.

To meet all the Class B volatility specifications, calculations showed it would be necessary to blend together 60 vol-% of the Platformate® blend, 30 vol-% of a C_5-C_6 cut previously distilled out from the hydrocracked shale oil naphtha product, and 10 vol-% of butanes. For practical considerations in the laboratory, the 10 vol-% of butanes was not blended with the liquids noted above.

An analysis of the C_5-C_6 fraction having a Research octane number of 70.5 is given in Table 27.

The actual gasoline blend sent to the USAF consisted of 2:1 volume blend of Platformate and the C_5-C_6 cut. Analyses of this blended gasoline are given in Table 28 and show that this gasoline meets all the chemical and antiknock requirements as outlined in Federal Specification VVG-1690B, July 1, 1978. A clear Research octane number of 87.2 was determined for this blend. A detailed isomer distribution analysis is given in Table 29.

The final Special Grade gasoline blend calculated by adding the equivalent of 10 vol-% butanes to the blended gasoline is shown in Table 30. This blend does not meet the Class B volatility specs for vapor pressure and TVL at 20°C but falls between the Class B and C gasolines. A slight adjustment in butane concentration would be sufficient to bring the gasoline either to a Class C or B volatility.

Conclusions

Naphtha derived from hydrocracking shale oil can be catalytically reformed to yield high octane gasoline blending components. The C_5 plus liquid yield varied linearly from 85 vol-% at 89 RONC to 70 vol-% at 104 RONC. Overall, this shale oil naphtha cut proved to be an excellent Platformer feed and gave yields comparable to petroleum-derived naphtha.

TABLE 22. NAPHTHA SAMPLE FROM HYDROCRACKING

Analysis	
API Gravity at 60°F	58.5
Sp.Gr. at 60°F	0.7447
Distillation (D-86), °F	
IBP	217
5%	224
10%	227
20%	230
30%	234
40%	240
50%	246
60%	250
70%	256
80%	266
90%	280
95%	293
EP	338
% Over	99.0
% Botts.	1.0
Sulfur, ppm	110.5
Nitrogen, ppm	<0.1
Oxygen, ppm	117
Carbon, wt-%	82.01
Hydrogen, wt-%	14.35
Mercaptan, ppm	0.5
FIA, vol-%	
A	7.8
O	1.1
P + N	91.1
RON, Clear (micro)	54.6

GLC	Wt-%
i-C_4	-
n-C_4	-
i-C_5	-
n-C_5	-
2-MP	-
3-MP	-
2,2 DMB	-
2,3 DMB	-
n-C_6	-
C_7 P	16.72
C_8 P	22.00
C_9 P	14.49
C_{10} P	2.45
C_{11} P	
C-C_5	-
MCP	-
C-C_6	0.02
C_7n	11.96
C_8n	13.90
C_9n	8.15
C_{10}n	0.91
C_{11}n	
Benzene	0.0
Toluene	2.9
C_8 arom	4.8
C_9+ arom	0.7
Total	8.4
Olefins	1.0

TABLE 23. HYDROTREATED PLATFORMER FEEDSTOCK

API Gravity at 60°F	62.0
Sp. Gr. at 60°F	0.7313
Distillation, (D-86), °F	
IBP	194
5%	204
10%	208
20%	214
30%	216
40%	220
50%	224
60%	227
70%	232
80%	238
90%	248
95%	254
EP	298
% Over	99.0
Molecular Weight	104
Sulfur, ppm	<0.1
Nitrogen, ppm	0.20
Carbon, wt-%	83.38
Hydrogen, wt-%	15.04
Chloride, ppm	4.4
Oxygen, ppm	<10
Mercaptan Sulfur, wt-%	0.0001
Lead, ppb	<20
Arsenic, ppb	1.4
Bromine Index	131.7
RON, Clear (micro)	56.4
PONA, vol-%	
P	61
O	0
N	34
A	5
FIA, vol-%	
A	5.5
O	-
P + N	94.5

TABLE 24. COMPONENT ANALYSIS OF HYDROTREATED PLATFORMER FEEDSTOCKS

GC Analysis, Wt-%

Aromatics	
Toluene	3.8
EB	0.5
p-Xylene	0.5
m-Xylene	1.1
o-Xylene	0.4
Total Aromatics	6.3
Paraffins and Naphthenes	
i-C_5	0.44
n-C_5	0.39
2,2-DMB	0.02
Cyclo C_5	0.02
2,3-DMB	0.17
2-MP	1.27
3-MP	0.85
n-C_6	1.22
MCP	0.95
2,2-DMP	0.05
2,4-DMP	0.19
Cyclo C_6	0.21
3,3-DMP	0.09
1,1-DMCP	0.44
2-MH	6.65
2,3-DMP	1.58
1-cis-3-DMCP	2.61
3-MH	7.03
1-t-3-DMCP	1.91
1-t-2-DMCP	2.14
3-EP	0.57
n-C_7	6.76
1-C-2-DMCP	1.48
MCH	4.77
1,1,3-TMCP	0.94
2,2-DMH	0.23
ECP	2.59
2,5-DMH	1.42
2,4-DMH	1.48
1-t-2-C-4-t-MCP	1.73
1-t-2-C-3-t-MCP	0.92
3,3-DMH	0.21
1,1,2-TMCP	0.41
2-M-3-DP + 2,3-DMH	1.07
1-c-2-t-4-t-MCP	0.53
1-c-2-t-3-t-MCP	0.34
2-MH + 3-M-3-EP	5.94
1-c-2-c-4-5-MCP + 4-MH + 3,4-DMH	3.40
3-EH + 3-MH + 1,1-DMCH	6.68
1-t-4-DMCH + 1-C-3-DMH	2.28
1-MC-3-ECP	2.02
1-M-t-3-2-ECP + 1-M-1-ECP	2.90
1-C-2-C-3-t-MCP + 1-t-2-DMCH	1.04
1-t-3-DMCH + 1-c-4-DMCH	1.89
IPCP	0.17
n-O	4.71
1-M-c-2-ECP	0.54
1-c-2-DMCH	0.46
ECH + n-P-c-P	1.45
C_9 Naphthenes	2.23
C_9 Paraffins	3.71
Total P + N	93.7

See Table 29 for compound definitions.

TABLE 25. PLATFORMER PRODUCT ANALYSES

Period	1	2	3	4	5	6	7	8	9
API Gravity at 60°F	50.5	49.6	47.8	47.4	45.3	44.3	40.6	40.2	50.9
Sp. Gr. 60/60°F	0.7775	0.7813	0.7892	0.7909	0.8003	0.8049	0.8222	0.8241	0.7758
Distillation (D-86), °F									
IBP	129	144	136	136	128	122	120	121	140
5%	175	178	166	165	158	154	154	158	178
10%	188	190	182	180	176	173	177	178	191
20%	206	206	201	200	200	199	208	209	206
30%	217	217	216	215	217	218	230	232	218
40%	226	225	226	227	230	232	242	244	226
50%	234	234	236	238	241	243	250	252	233
60%	242	242	246	252	251	252	256	258	240
70%	251	253	256	259	260	260	264	265	250
80%	264	265	268	268	270	270	273	274	262
90%	282	282	284	283	285	283	286	285	280
95%	296	295	300	296	300	299	300	300	298
EP	350	328	331	337	336	338	346	356	316
% Over	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
% Bottoms	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
FIA, vol-%									
A	50.2	52.4	57.2	58.9	64.8	67.1	77.7	79.2	49.1
O	1.3	1.3	1.3	1.3	1.3	1.4	1.1	.9	1.6
P + N	48.5	46.3	41.5	39.8	33.9	31.5	21.2	19.9	49.3
Octane Number									
RONC	90.2	91.2	95.2	95.9	98.2	99.8	103.7	104.3	88.7
RON + 3 TEL	98.7	99.3	102.3	102.0	104.2	104.7	107.6	109.2	97.6
MON	80.6	81.2	84.4	86.8	87.3	88.5	92.0	92.4	79.5

TABLE 26. PLATFORMER PRODUCT BLEND

API Gravity at 60°F	47.2
Sp. Gr. 60/60°F	0.7918
Distillation (D-86), °F	
IBP	137
5%	175
10%	189
20%	207
30%	221
40%	230
50%	238
60%	247
70%	257
80%	270
90%	287
95%	306
EP	351
% Over	97.5
% Bottoms	1.0
% Loss	1.5
Dry Point, °F	320
RON Clear	95.5
MON Clear	84.8
Reid Vapor Pressure, psi	3.3

TABLE 27. C_5-C_6 FRACTION

		GC	Wt-%
API Gravity at 60°F	77.3	i-C_4	trace
Sp. Gr. 60/60	0.6777	n-C_4	0.1
Distillation (D-216), °F		i-C_5	7.6
IBP	120	n-C_5	8.7
5%	130	2,2-DMB	0.3
10%	134	CP	0.6
20%	137	2,3-DMB	2.7
30%	140	2-MP	19.5
40%	144	3-MP	13.0
50%	148	n-C_6	16.9
60%	152	MCP	13.1
70%	155	CH	1.9
80%	159	Bz	0.9
90%	166	C_7+	14.6
95%	174	Olefins	0.1
EP	240		
% Over	99.0		
% Bottoms	1.0		
Nitrogen, ppm	0.13		
Sulfur, ppm	32		
Vapor Press., psi	7.7		
RON Clear	70.5		
MON Clear	68.8		

TABLE 28. GASOLINE BLEND

API Gravity at 60°F	56.2
Sp. Gr. 60/60°F	0.7539
Distillation (D-86), °F	
IBP	135
5%	151
10%	159
20%	170
30%	180
40%	192
50%	206
60%	223
70%	244
80%	261
90%	282
95%	306
EP	323
% Over	98.0
% Loss	1.0
% Bottoms	1.0
Dry Point, °F	
Carbon, wt-%	85.86
Hydrogen, wt-%	13.70
Nitrogen, ppm	0.3
Oxygen, ppm	352
Sulfur (unleaded), ppm	5.6
Reid Vapor Pres., psi	5.1 (35.16 kPa)
FIA, vol-%	
A	39.0
O	1.1
P + N	59.9
Cu Strip Corrosion	1A
Antiknock Content	
Lead (unleaded)	<0.01 g/gal
Manganese (unleaded)	<0.1 ppm
Temperature, °C, min. at V/L Ratio = 20	71.3

Existent Gum, mg/100 mL	1
Unwashed Gum, mg/100 mL	1
Oxidation Stability, min.	>1200
RON Clear	87.2
MON Clear	79.8
R+M/2	83.5
Water and Sediment, vol-%	<0.005
Benzene, vol-%	1.2
Phosphorus (unleaded), g/gal	<0.0003

TABLE 29. GASOLINE BLEND

Complete Isomer Distribution

	Wt-%
Aromatics	
Benzene	1.5
Toluene	18.5
Ethylbenzene	2.7
p-Xylene	4.7
m-Xylene	9.6
o-Xylene	5.9
C_9+ Aromatics	4.2
Total A	46.9
Olefins (Total)	1.0
Paraffins and Naphthenes	
1. Propane	
2. Isobutane	
3. n-Butane	0.10
4. Isopentane	4.49
5. n-Pentane	4.04
6. 2,2-Dimethylbutane	0.14
7. Cyclopentane	0.23
8. 2,3-Dimethylbutane	0.56
9. 2-Methylpentane	4.30
10. 3-Methylpentane	3.22
11. n-Hexane	5.18
12. Methylcyclopentane	3.03
13. 2,2-Dimethylpentane	0.59
14. 2,4-Dimethylpentane	1.19
15. 2,2,3-Trimethylbutane	0.10
16. Cyclohexane	0.54
17. 3,3-Dimethylpentane	0.47
18. 1,1-Dimethylcyclopentane	0.11
19. 2-Methylhexane	3.93
20. 2,3-Dimethylpentane	1.28
21. 1-cis-3-Dimethylcyclopentane	0.10
22. 3-Methylhexane	4.50
23. 1-trans-3-Dimethylcyclopentane	0.15
24 1-trans-2-Dimethlycyclopentane	0.16
25. 3-Ethylpentane	0.44
26. 2,2,4-Trimethylpentane	0.02
27. n-Heptane	3.50
28. 1-cis-2-Dimethylcyclopentane	0.02
29. Methylcyclohexane	0.03
30. 1,1,3-Trimethylcyclopentane	0.02
31. 2,2-Dimethylhexane	0.25
32. Ethylcyclopentane	0.04
33. 2,5-Dimethylhexane	0.38
34. 2,4-Dimethylhexane	0.70
35. 2,2,3-Trimethylpentane	0.01
36. 1-trans-2-cis-4-Trimethylcyclopentane	

TABLE 29. GASOLINE BLEND (Continued)

Paraffins and Naphthenes (Cont.)

37.	1-*trans*-2-*cis*-3-Trimethylcyclopentane	0.01
38.	3,3-Dimethylhexane	0.27
39.	2,3,4-Trimethylpentane	0.03
40.	1,1,2-Trimethylcyclopentane	0.01
41.	2,3,3-Trimethylpentane	0.03
42.	2-Methyl-3-ethylpentane	0.51
43.	2,3-Dimethylhexane	
44.	1-*cis*-2-*trans*-4-Trimethylcyclopentane	
45.	1-*cis*-2-*trans*-3-Trimethylcyclopentane	
46.	2-Methylheptane	1.52
47.	3-Methyl-3-ethylpentane	
48.	1-*cis*-2-*cis*-4-Trimethylcyclopentane	
49.	4-Methylheptane	1.07
50.	3,4-Dimethylhexane	
51.	3-Ethylhexane	
52.	3-Methylheptane	2.35
53.	1,1-Dimethylcyclohexane	
54.	1-*trans*-4-Dimethylcyclohexane	
55.	1-*cis*-3-Dimethylcyclohexane	
56.	1-Methyl-*cis*-3-ethylcyclopentane	0.03
57.	1-Methyl-*trans*-3-ethylcyclopentane	
58.	1-Methyl-*trans*-2-ethylcyclopentane	0.07
59.	1-Methyl-1-ethylcyclopentane	
60.	1-*cis*-2-*cis*-3-Trimethylcyclopentane	
61.	1-*trans*-2-Dimethylcyclohexane	
62.	1-*trans*-3-Dimethylcyclohexane	
63.	1-*cis*-4-Dimethylcyclohexane	
64.	Isopropylcyclopentane	
65.	*n*-Octane	1.71
66.	1-Methyl-*cis*-2-ethylcyclopentane	
67.	1-*cis*-2-Dimethylcyclohexane	0.04
68.	Ethylcyclohexane	0.02
69.	*n*-Propylcyclopentane	
	C_9 Naphthenes	0.09
	C_9 Paraffins	0.39
	C_{10} Naphthenes	0.13
	C_{10} Paraffins	
	C_{11} Naphthenes	
	C_{11} Paraffins	
	C_{12} P + N	
	Total P + N:	52.1

Totals

TABLE 30. SPECIAL GASOLINE

API Gravity at 60°F	60.5
Sp. Gr. 60/60°F	0.7370
Distillation (D-86), °F	°F
IBP	96
10%	125
30%	168
50%	195
70%	235
90%	278
EP	306
RON Clear	87.9
MON Clear	80.8
$\frac{R + M}{2}$	84.4
	psi
Reid Vapor Pressure	11.1
Temperature, °C min at V/L Ratio = 20	53.0

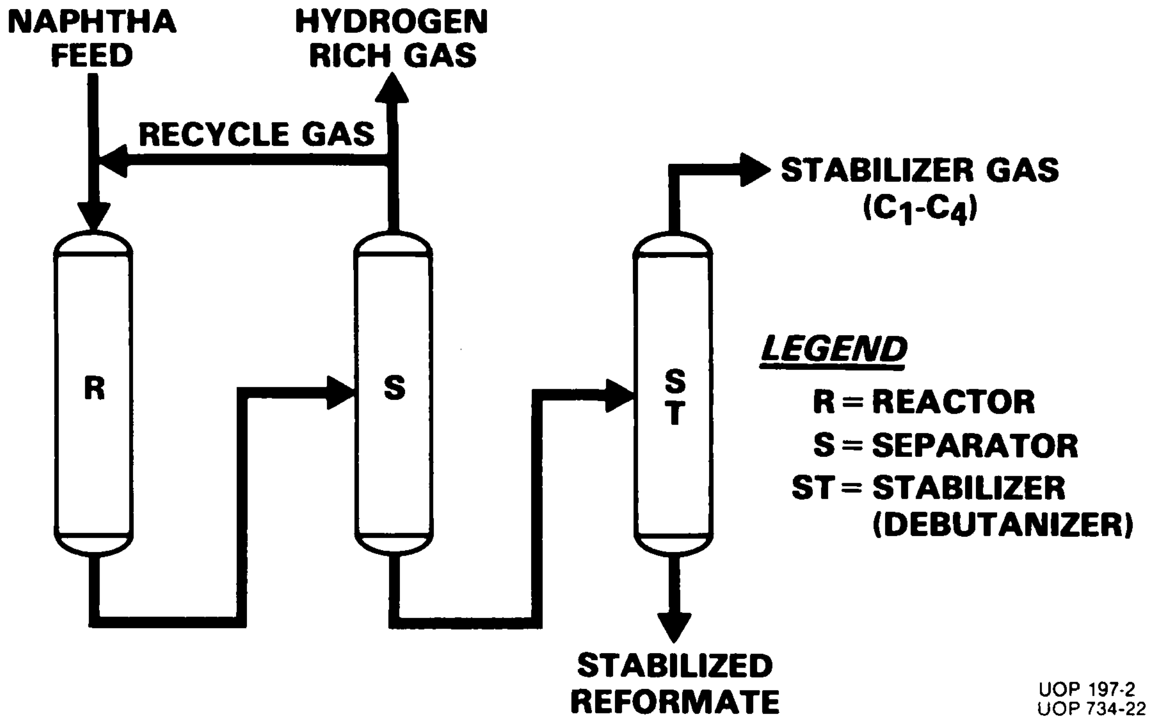


FIGURE 6

NAPHTHA REFORMING PILOT PLANT

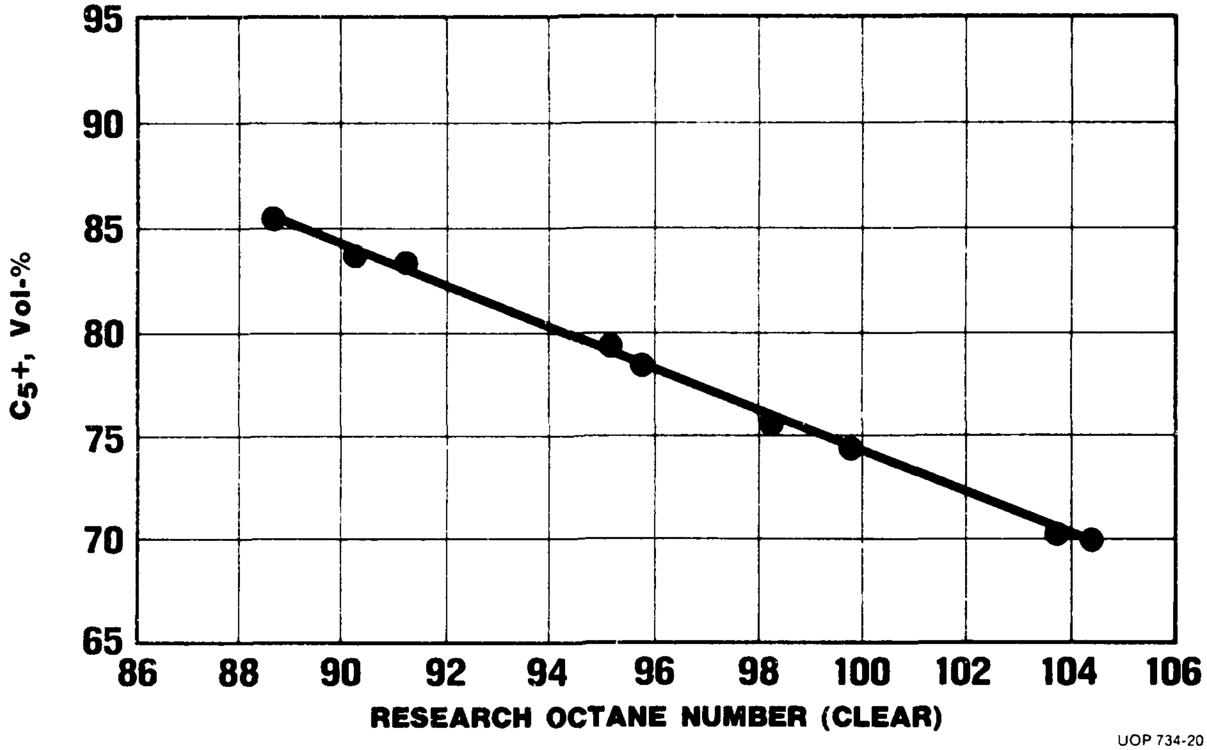


FIGURE 7

PLATFORMING YIELD — OCTANE STUDY
OCCIDENTAL SHALE OIL
LIQUID AND HYDROGEN YIELDS

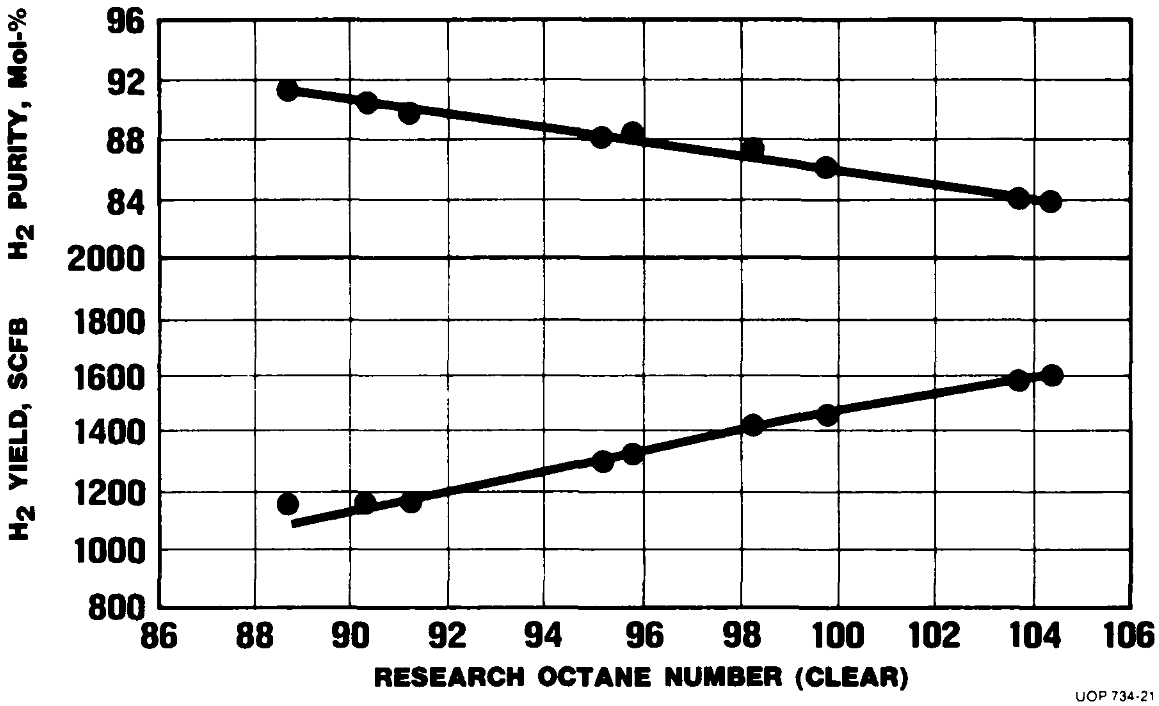


FIGURE 8

PLATFORMING YIELD — OCTANE STUDY OCCIDENTAL SHALE OIL LIQUID AND HYDROGEN YIELDS

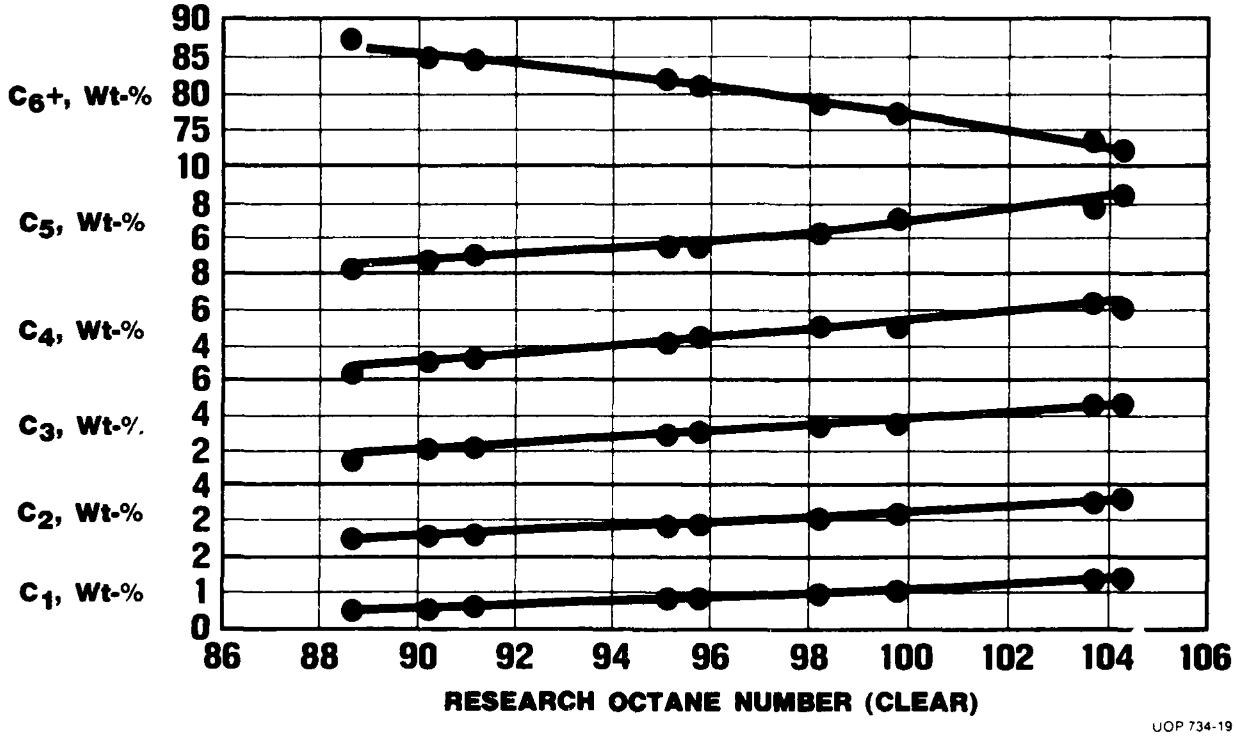


FIGURE 9

PLATFORMING YIELD — OCTANE STUDY OCCIDENTAL SHALE OIL

SECTION V

ARSENIC MANAGEMENT STUDIES

Shale oils produced by current retorting operations contain arsenic in such concentrations that it deserves special attention. Two approaches to the shale oil arsenic management problem have been investigated in this program:

1. Crude shale oil arsenic solubilization

2. Deposited arsenic passivation or extraction.

Shale Oil Arsenic Solubilization

The first hypothesis investigated involved converting the arsenic in the raw shale oil to a water soluble compound. This might be accomplished by injecting a reagent downstream of the retort into the oil-water mixture. With intimate mixing of the reagent, oil and water may convert the arsenic into water soluble compounds. After the two phases are allowed to coalesce, the water phase is drained off leaving a shale oil with reduced arsenic content. The water containing arsenic could then be further treated, if necessary, to render it environmentally safe.

Desalted Occidental shale oil with 19 ppm arsenic was utilized as the hydrocarbon source for a series of experiments attempting to convert arsenic into water soluble compounds. For these experiments, the water, reagent and shale oil were intimately contacted utilizing a shear-type mixer. Each test was performed by mixing the oil and water for 15 minutes at about 95°C (200°F). The type of emulsion formed while adding various reagents was observed, and the arsenic level left in the oil was measured after each test.

A summary of results is shown in Table 31. Arsenic solubilization ranged from 13 to 52%. The removal of arsenic was probably accomplished by the formation of an insoluble material that is associated with the emulsion. The use of a wide range of reagents along with shear mixing to effect water solubilization of arsenic from shale oil does not appear to be very promising.

Arsenic Passivation and Extraction

The high concentration of arsenic in the raw shale oil and its removal and containment on the first-stage hydrotreater catalyst poses some special handling problems. Before arsenic-laden catalysts can be disposed of as non-hazardous wastes, the aqueous solubility of arsenic as measured by the EPA Toxicity test must be reduced to less than 5 ppm. In an effort to meet this requirement for safe disposal, the following objectives were considered:

1. Ascertain the composition of arsenic-containing species on used catalyst.

2. Determine the arsenic solubility of aqueous extracts of used catalysts.

3. Evaluate methods of passivating soluble arsenic.

4. Determine the effect of various gases on arsenic volatility.

5. Evaluate the extraction behavior of arsenic from untreated and thermally treated used catalysts using various solvents.

6. Determine the conditions for complete dissolution of used catalysts.

Experimental Procedure

Samples of spent catalysts were thermally treated by spreading the catalyst pills inside a 1-inch silica tube. Three thermocouples were placed at the ends and middle of the catalyst bed. The catalyst sample was held in place by tufts of quartz wool. Rubber stoppers fitted with glass tubes allowed controlled atmospheres to be passed through the sample gas flow as adjusted to 600 mL/min.

Heating was accomplished by a 30 cm-long split tube furnace. Once the desired temperature had been reached, the silica tube containing the sample was inserted. The furnace temperature was held to within ±10°C. Cooling was achieved by removing the apparatus from the furnace. When cool, the catalyst was removed from the tube. The sample was analyzed for arsenic and sulfur.

Thermally treated and as-received samples were extracted in various solvents. Five gram samples were added to Erlenmeyer flasks containing 200 mL of extractant and shaken on a wrist shaker for 3 hours. The resulting slurry was filtered and washed. The catalyst residue and filtrate were analyzed for arsenic and sulfur.

Elemental Analysis

The elemental analyses of spent catalyst beds removed from two first-stage hydrotreating pilot plant reactors show that the arsenic concentration declines rapidly downward through the bed. As shown in Table 32, iron exhibits a similar profile while the remaining elements are fairly evenly distributed. The major difference between the two catalysts is the much higher arsenic level on the used catalyst designated as "Catalyst 2". The relative concentrations of the arsenic and iron throughout the catalyst bed are not significantly different.

An identification of the arsenic compounds present on the catalyst was considered necessary in order to determine the best methods to either fix the leachable arsenic by further chemical reaction or convert the arsenic into a highly soluble form. X-ray diffraction patterns obtained for the two samples were analyzed and the results are summarized in Table 33. The peak positions were calculated, and a manual search was made of the powder diffraction files in order to determine which compounds were present.

The γ-Al_2O_3 of the catalyst base is a major component in both samples. Trace levels of α-quartz and boehmite were also detected. The rest of the standard patterns listed fit the sample patterns well, but the actual components present may have slightly different compositions.

Both samples contain a major phase similar to pyrrhotite [$Fe_{(1-x)}S$, where x ≤ 0.1]. A slight increase in sulfur content would lead to a mixture of pyrrhotite and pyrite (FeS_2). There is evidence of pyrite in the sample designated "Catalyst 1".

$Co_{0.84}Ni_{0.16}As_{1.04}$ is the cobalt analog of niccolite $(NiAs)_1$. Their patterns are similar. The peaks in the pattern more closely match the former ($Co_{0.84}Ni_{0.16}As_{1.04}$); however, the actual compound present may have a formula somewhere between the two arsenides.

Although some of the peaks for the two used catalysts match the pattern of $Cu_{24}As_{12}S_{31}$, there was no copper detected in the elemental analysis. It is possible a similar compound was present with other metals substituted for the copper.

The chloroform-washed samples were subjected to a modified EPA Toxicity test for arsenic. The modification in procedure was the use of 10 grams in place of 100 gram samples. As shown in Figure 10, the As solubility of the chloroform-washed catalyst appears to be a linear function of the As content of the catalyst. In order to meet the EPA limit, the catalyst would have to contain less than 0.2 wt-% As.

Metal salts were blended with the used catalyst, then heated in an inert atmosphere in an attempt to fix the arsenic as metal arsenides or metal arsenous sulfides. It was anticipated that conversion to these compounds would cause the arsenic to be less soluble; however, as shown in Figure 10, this proved not to be the case.

The EPA test was performed on several used catalysts that had been previously extracted with sulfuric and nitric acid solutions. The arsenic solubility was decreased; however, the arsenic level remaining on the catalyst was still too great for direct disposal. As shown in Figure 10, in order to meet the EPA limit, it will be necessary to reduce the As content on the catalyst to about 0.5 wt-%.

If essentially all of the arsenic could be volatilized in a roasting process, arsenic collection would be feasible. Considering the relatively high vapor pressures of arsenic, arsenic sulfide and arsenic oxide, it appears that arsenic would be removed at elevated temperatures in either oxidizing, reducing, or neutral atmospheres.

As shown in Figure 11, the volatility of arsenic from spent catalyst was dependent upon temperature, residence time and atmosphere. It appears that a temperature of about 500°C (932°F) is required to break down the original arsenic minerals and to ensure adequate vapor pressure of volatile species. If the rate of arsenic volatilization can be increased, arsenic might be recovered by such a process.

Extractants were chosen to discern the state of arsenic present on the catalyst following thermal pretreatment. $H_2SO_4/FeCl_3$ and HNO_3 are strong oxidizing agents capable of oxidizing sulfide minerals. Sulfuric acid is a non-oxidizing acid which can solubilize sulfates and arsenates. Sodium sulfide forms complex anionic arsenous sulfides which are highly soluble.

Arsenic extraction results, from catalysts that were thermally oxidized at the severe conditions of 500°C in 5% O_2, were very similar. The data shown in Figure 12 indicate that the arsenic has probably been converted to an arsenate.

The data plotted in Figure 13 indicate that catalysts pretreated under rather neutral conditions, 25% H_2O/75% N_2, were more effectively extracted with oxidizing acids than with the other leachants. The arsenous sulfide minerals are only beginning to be broken down at the highest temperature, 600°C (1112°F).

As shown in Figure 14, using SO_2 in the thermal treatment step produces a different response to the extractants. At temperatures below 500°C, the

SO_2 atmosphere produced little change in the arsenic chemistry. At 500°C, SO_2 reacted slowly with carbon to form sulfur and CO_2 and converted the metal arsenous sulfides to more leachable forms. All of the extractants remove approximately the same level of arsenic.

None of the thermal pretreatments produced a material that allowed high levels of arsenic extraction. In the best case, about 80% of the arsenic was removed by a combination of thermal treatment and leach extraction. Increasing the leachant concentration to increase the arsenic extraction would result in considerable alumina dissolution.

An alternative approach to arsenic recovery utilized solution oxidation. Acid digestion of as-received used catalyst was performed in a stoichiometric quantity of sulfuric acid, assuming the catalyst composition to be entirely Al_2O_3 with the following reaction:

$$Al_2O_3 + 3\ H_2SO_4 \rightarrow Al_2(SO_4)_3 + 3\ H_2O$$

The digestion was carried out under reflux for 8 hours. In order to obtain high recoveries of the elements, the reaction had to be carried out at a positive solution potential. This was accomplished by adding 3 wt-% HNO_3 to the sulfuric acid. As shown in Table 34, 90% recovery of arsenic was achieved with both the 10 and 20 wt-% sulfuric acid solutions. Only molybdenum was poorly recovered in this solvent; however, molybdenum can be recovered from the residue using other techniques. Digestion of thermally treated catalysts was not as effective in recovering arsenic as solution oxidation of the as-received used catalyst.

Conclusions

1. Used catalysts from processing shale oil will contain higher levels of soluble arsenic than allowed by the EPA for non-hazardous disposal.

2. Much of the arsenic is present on the catalyst as thermally stable metal arsenides and metal arsenous sulfides.

3. It was not possible to fix or passivate the arsenic on the catalyst in an insoluble form by thermally treating the catalyst with or without additives.

4. Leachants, which do not dissolve excessive quantities of alumina, extract only about 20% of the arsenic from non-thermally treated catalysts.

5. Of the thermal treatments investigated, only dilute oxidizing atmospheres, 5% O_2 or less, at elevated temperatures, $\geq$500°C, for extended time result in appreciable arsenic volatilization. This indicates that arsenic is not present on the catalyst as a simple sulfide, oxide or metallic compound.

6. Increasingly severe thermal pretreatments allow up to 75% of the arsenic to be extracted by dilute leachants.

7. Both temperature and gas composition are important variables in converting the arsenic to a leachable form.

8. Results of toxicity tests on previously treated catalysts indicate that high extraction levels are necessary before the residue is acceptable.

9. Digestion of as-received spent catalyst requires a high solution potential in order to achieve good extractions.

10. Digestion of thermally oxidized catalysts yields poorer arsenic extractions than solution oxidation of the as-received catalysts.

11. Topics worthy of further investigation include the evaluation of different ratios of As, Fe, C and S on arsenic volatility and solubility; the recovery of arsenic by thermal means; the development of methods to recover arsenic from acidic solutions; and the determination of the minimum acid necessary to achieve good extractions of arsenic without excessive dissolution.

TABLE 31. SHALE OIL ARSENIC SOLUBILIZATION STUDY

Arsenic in Feed = 19 ppm

Reagent	Observation	Arsenic in Oil, ppm
10% KOH	Emulsion stable, broken by addition of isooctane/methanol.	10.8
10% H_2SO_4	No emulsion formed.	16.6
50% Acetic acid	Formed emulsion which slowly broke.	14.7
10% Na_2S	Formed emulsion which did not break with isooctane/methanol treatment.	
	1) One hour at 220°C (430°F) under 100 ATM of N_2-broke.	11.7
	2) Centrifuged at 7000 ppm, part of the emulsion broke.	9.1

TABLE 32. FIRST-STAGE HYDROTREATER, SPENT CATALYST ANALYSIS

Sample Location	Element, wt-%							
Catalyst 1	Fe	C	N	S	H	As	Mo	Co
Upper Section	6.3	10.4	0.47	9.3	1.6	2.4	+	+
Upper Middle	4.5	10.5	0.34	8.6	1.4	1.2	+	+
Middle Section	1.0	13.4	0.57	8.2	1.6	0.32	+	+
Lower Middle	0.4	13.3	0.59	7.8	1.4	0.12	+	+
Lower Section	0.4	14.1	0.67	7.5	1.3	0.07	+	+
Catalyst 2								
Top	6.0	9.11	3.9	6.2		8.4	+	+
Top Middle	3.7	10.2	0.43	6.4		5.6	+	+
Middle	1.9	10.1	0.43	5.7		3.4	+	+
Bottom Middle	1.0	10.2	0.85	5.8		1.6	+	+
Bottom	0.9	10.3	0.22	5.5		1.3	+	+

+ = Present.

TABLE 33. DIFFRACTION DATA ON USED CATALYSTS

Compound Identification	Catalyst 1 Upper Section	Catalyst 2 Upper Section
γAl_2O_3	m	m
αSiO_2	t	t
AlO(OH) Boehmite	t	
$Fe_{(1-x)}S$ Pyrrhotite	m	m
FeS_2 Pyrite		t
$Co_{0.84}Ni_{0.16}As_{1.04}$	t	m
$Cu_{24}As_{13}S_{31}$	t	m

m = major

t = trace

TABLE 34. DIGESTION OF USED CATALYST

Used Catalyst Analysis: Arsenic, wt-% 1.16

Digestion Solution		As Extraction, %
H_2SO_4, wt-%	HNO_3, wt-%	
10	-	24
10	3	90
20	-	23
20	3	90
40	-	24
40	3	72

Thermally Treated Catalyst
Extracted in 40 wt-% H_2SO_4

Thermal Treatment			% As Removed		
Temp., °C	Gas	Time, Hr	Volatilization	Extraction	Total Removal
550	5% O_2	6	69	50	74
650	5% O_2	2	58	53	80
250	5% O_2	6	9	74	76

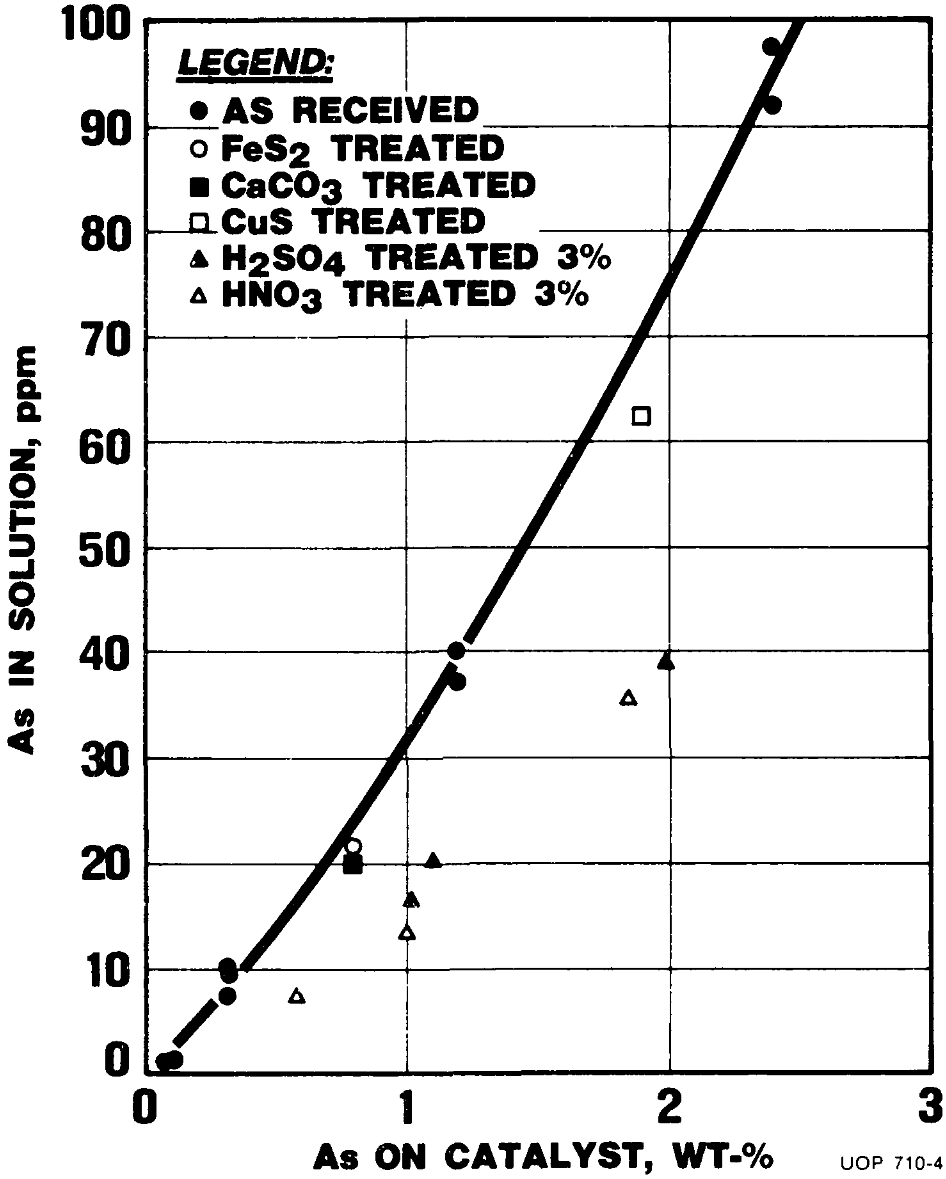


FIGURE 10

SIMULATED EPA TOXICITY TEST ON USED CATALYST

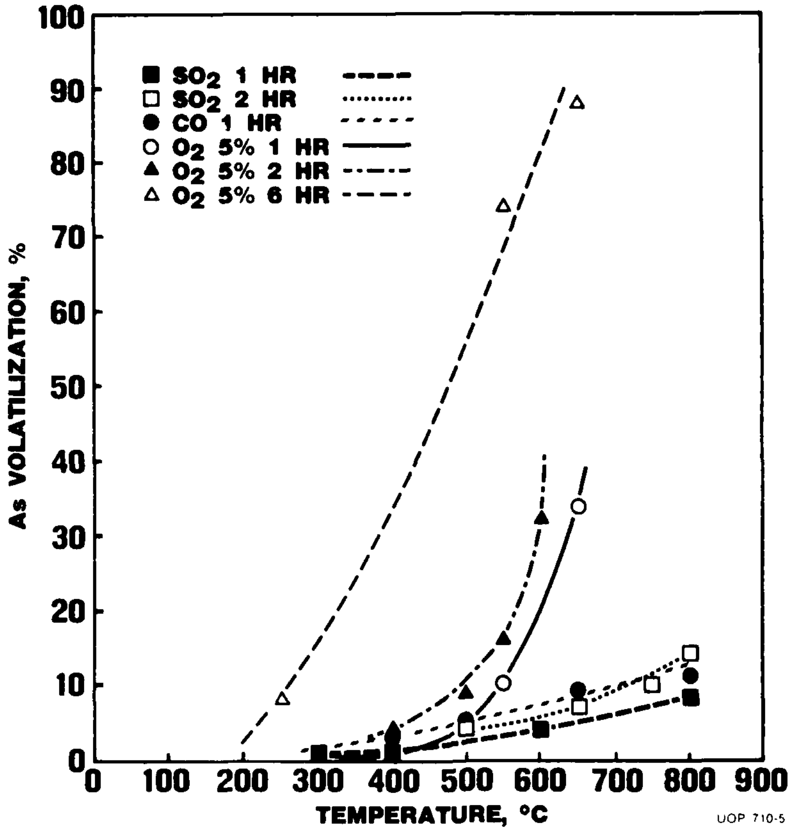


FIGURE 11

EFFECT OF THERMAL TREATMENT ON ARSENIC VOLATILIZATION

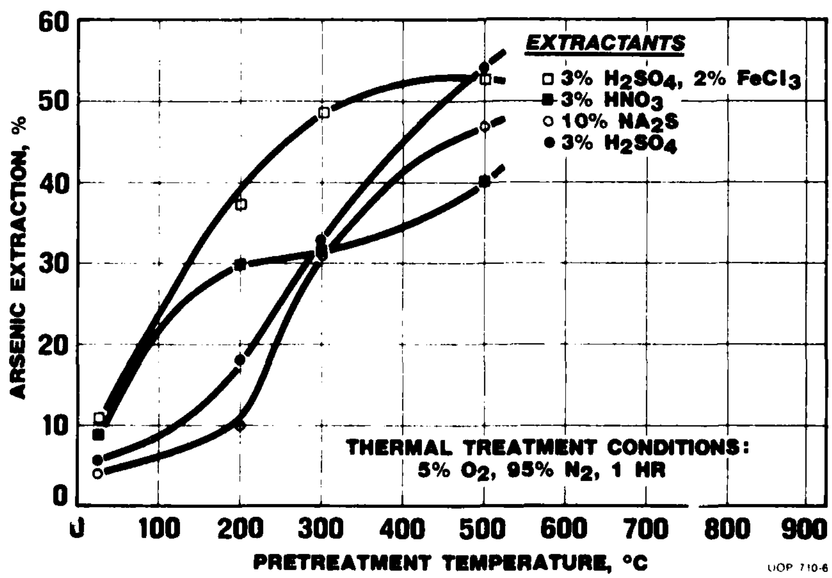


FIGURE 12

EFFECT OF SEVERE OXIDATION ON ARSENIC EXTRACTION FROM USED CATALYST

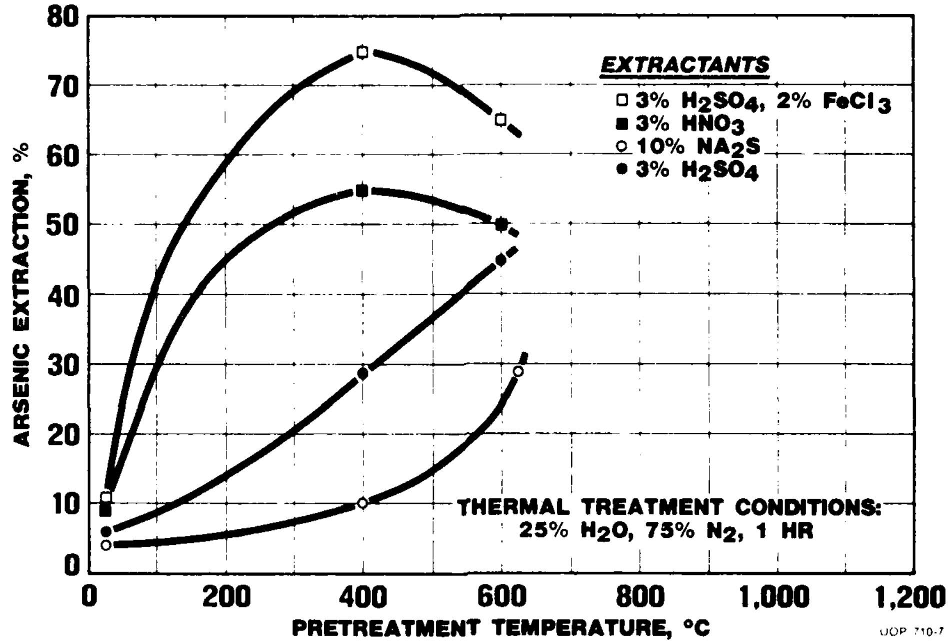


FIGURE 13

EFFECT OF MILD OXIDATION ON ARSENIC EXTRACTION FROM USED CATALYST

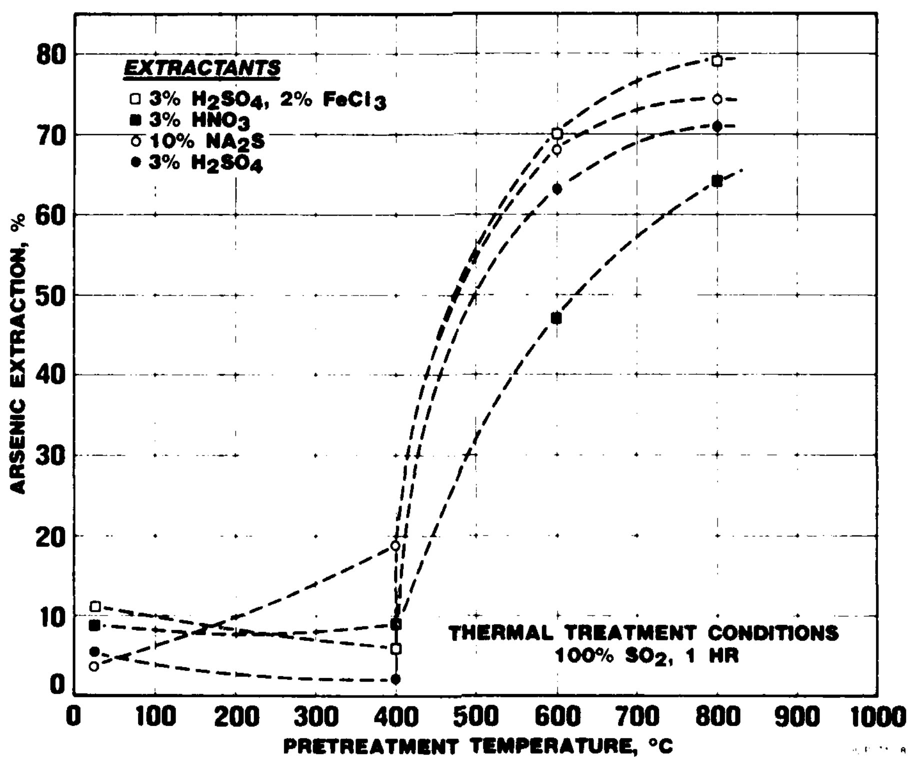


FIGURE 14

EFFECT OF SULFUR TREATMENT ON ARSENIC EXTRACTION FROM USED CATALYST

SECTION VI

FOULING

The Monirex® Fouling Monitor has been used to determine the thermal fouling properties of aged Occidental desalted shale oil, an Arabian Light Berri petroleum oil and blends of these oils. In addition, the thermal fouling properties of a severly hydrotreated Occidental shale oil, a JP-8 fuel derived from the hydrotreated shale oil and a relatively fresh Paraho shale oil have also been determined.

Experimental Development

The UOP Monirex Fouling Monitor, previously described in considerable detail in the Phase II report, was used to evaluate the relative thermal fouling properties of shale and petroleum oils. This unit measured the temperature of the fluid (T_F), the wire (T_W) and the heat input (Q) to the wire. Since the wire area was known, it was possible to calculate the heat transfer coefficient (h) as well as the fouling factor (R_F) and the fouling rate (dR_F/dt).

Chemical analyses of materials used in this study including the Occidental desalted and high-pressure (second-stage) hydrotreated shale oil, the JP-8 derived from the hydrotreated oil, and the Arabian Light Berri petroleum desalted crude oil are shown in Table 35. Significant differences between the desalted petroleum and shale oils are the higher Bromine number, gravity and nitrogen content of the shale oil and the higher sulfur content in the petroleum oil. The hydrotreated Occidental shale oil, however, has a significantly lower Conradson carbon, Bromine number, iron, sulfur, nitrogen content and gravity than the original desalted oil.

Unfortunately, the state-of-the-art in predicting fouling has not advanced sufficiently to predict potential thermal fouling characteristics based on chemical analysis. However, as will be shown later, it is apparent that reduction in the sulfur and unsaturated compounds content as well as metals such as iron and nickel did result in lower fouling in the hydrotreated shale oil.

The thermal fouling characteristics of the Arabian Light Berri desalted petroleum crude and Occidental shale oil previously evaluated in June, 1980, were again reevaluated in March, 1981. Data from both tests are given in Tables 36 and 37, and in Figures 15 and 16.

The estimated age of the Occidental desalted shale oil by June, 1980 was 13 months, and 22 months by March, 1981. The Arabian Light Berri petroleum desalted crude was in storage about 8 months by June, 1980, and 17 months by March, 1981. Both oils were sparged with nitrogen when received and stored at 4.4°C (40°F) until ready for test. Prior to testing they were moved into a 40°C (105°F) room and stored there during the entire test period.

Discussion of Results

A regression analysis was made of the data and the fouling rate calculated for the 200° to 400°C (392° to 752°F) temperature range. As shown in Table 38, the aging of the Occidental desalted shale oil and the Arabian Light Berri petroleum crude oil significantly reduced fouling on the iron wire.

To illustrate potential effects of aging, the 250°C (482°F) fouling data, were plotted (Figure 17) assuming the fouling rate decreased linearly or exponentially. These data suggest that the dR_F/dt of the Occidental desalted shale oil had probably decreased by a factor of 5 to 10 times after aging at 4.4°C (40°F) for 22 months, and the Arabian Light Berri desalted petroleum crude decreased by a factor of 1.5 to 2 times after aging for 8 months. It is apparent, therefore, that more meaningful fouling data could be obtained with fresh samples.

Because it is anticipated that the shale oils will be blended with petroleum stocks for processing, the thermal fouling properties of blends of the Arabian Light Berri desalted crude containing 10 and 30% (by weight) of the Occidental desalted shale oil were determined. The data from these test are given in Tables 39 and 40 and presented graphically in Figures 18 and 19. When compared with the 100% petroleum and 100% shale oil results, it is apparent from examining Figure 20 that there were no significant differences in the thermal fouling characteristics of the blends. Blending did not result in the formation of any new fouling components, and the data actually show a minor decrease in fouling tendencies. These two oils, however, are quite old and the effect of blending should be repeated with fresh samples.

The thermal fouling properties of a high-pressure hydrotreated Occidental shale oil were determined and these data are shown in Table 41 and Figure 21. These data show that the high-pressure hydrotreated shale oil was a low fouling material with an activation energy significantly higher than that of the original desalted oil. Although specific compounds have not been identified, it can be speculated that this reduction in fouling is due to the reduction in concentration of unsaturated sulfur and nitrogen compounds. Fouling rate data calculated from a regression analysis of the data in Figure 21 for the 200° to 400°C (392°–752°F) region are given in Table 38.

The thermal fouling characteristics of a JP-8 derived from the high-pressure hydrotreated Occidental shale oil were determined and these data are summarized in Table 42 and Figure 22. These data show that the JP-8 had fouling properties greater than the hydrotreated shale oil but slightly lower than the original desalted oil. Apparently the catalytic process, converting the hydrotreated oil to the JP-8, results in the production of products which can foul thermally on a heated iron wire. No data were available to identify these products. Fouling rates calculated for the 200° to 400°C (392°–752°F) region are shown in Table 38.

In the Phase II report, the relative thermal fouling properties of two Paraho shale oils were reported. The fouling reactions did not apparently follow a typical Arrhenius concept, and it was speculated that these deviations were due to the presence of oxygenates. More recent experiments indicate that excessive fouling of the probe was responsible.

The test method requires that a build-up of fouling deposit has only a minor effect on the surface area or diameter of the original wire. It was shown that at temperatures from 250° to 311°C (482°-592°F), a relatively long time of exposure of the iron wire at a constant voltage to Occidental desalted shale oil resulted in only minor changes in the fouling rate. The data from a similar set of experiments at 145° and 184°C (293° and 363°F) with the Paraho shale oil are summarized in Table 43 and Figure 23. It was obvious from the dramatic change in observed fouling rate that a build-up of deposit had occurred. Therefore, it was not possible with the high fouling materials to use the same experimental technique in which the probe temperature is increased during a run. A new probe must be used at each new temperature.

A new series of experiments were made with the Paraho shale oil employing a new probe for each new temperature (3 hours per test). Based on the data in Table 44 and shown in Figure 24, the new data are more reasonable and consistent than those obtained previously with the incremental increase in temperature technique. A regression analysis of the data was made, and the fouling rate in the 200° to 400°C (392°-752°F) range given in Table 38, confirms that the Paraho shale oil has a high fouling tendency.

During Phase II, Paraho shale oil was treated with a proprietary antifoulant resulting in a significant decrease in fouling rate. A second Paraho shale oil was also treated with the same proprietary antifoulant (40 ppm) and these fouling data, are given in Table 45 and Figure 24, also show a significantly reduced fouling rate.

Conclusions

The Monirex Fouling Monitor was used to determine the relative thermal fouling properties of aged Arabian Light Berri desalted petroleum, Occidental desalted shale oil and blends of these oils. In addition, the fouling properties of a hydrotreated Occidental shale oil, a JP-8 derived from this oil and a relatively new Paraho shale oil were also determined. These data, summarized in Table 38 and Figures 25 and 26, show that desalting and hydrotreating decrease the fouling tendency of shale oils, shale oils may have different fouling tendencies, and the aged Occidental shale oil had a fouling tendency similar to an Arabian Light Berri crude.

It was found that aging at 4.4°C (40°F), with relatively short periods at (40°C) 105°F, resulted in significant decreases in fouling rates. Since data are available for only two aging periods, it is difficult to project fouling rates to zero age. Although data are not available to show the fouling properties of a fresh sample, it can be speculated that an exponential decrease in fouling rate with aging indicates a rate 5 to 10 times higher for the fresh Occidental desalted shale oil than that found after 13 months aging, and up to 2 times greater for the Arabian Light Berri desalted petroleum oil when compared to those found after eight months. It is apparent, however, that the most meaningful data must be obtained with fresh samples.

Blending of the desalted Arabian Light Berri petroleum crude oil and the desalted Occidental shale oil at 70:30 or 90:10 ratios, by weight, had no significant effect on the fouling rates of either oil. These data indicate that blending did not result in the formation of any significant quantities of pro- or antifoulant materials. However, the activation energy of the fouling reactions of the blends were slightly higher than those of the original materials suggesting the possibility of a different fouling reaction mechanism. The original samples were quite old, with relatively low fouling rates, and it is apparent that these studies should be repeated with fresh oils.

The high-pressure hydrotreated Occidental shale oil had a very low fouling rate. Although the analytical data show substantial removal of unsaturated sulfur, iron and nitrogen compounds by hydrotreating, specific compounds responsible for fouling have not been identified. The activation energy of the hydrotreated oil fouling reaction is very high suggesting a different mechanism for the fouling reactions on the iron wire.

A JP-8 derived from the high-pressure hydrotreated Occidental desalted shale oil has a relatively low thermal fouling rate. This rate was slightly higher than that of the hydrotreated shale oil but lower than that of the original shale oil. Hydrocracking, the process used to make the JP-8, must apparently produce new precursors of fouling reactions as indicated by the reduction of the activation energy from 18 kcal to 6.5 kcal for the JP-8.

It was also shown that only low fouling materials such as the petroleum and the aged Occidental shale oil used can be evaluated with a single probe for all of the temperatures selected for fouling studies. A high fouling material, such as the relatively fresh Paraho shale oil, must be evaluated with a new probe at each new test temperature. Significant foulant build-up on the iron wire probe can change the wire surface area. Under these new conditions, it was shown that the Paraho shale oil fouling rate was approximately an order of magnitude higher than for the petroleum or Occidental shale oil.

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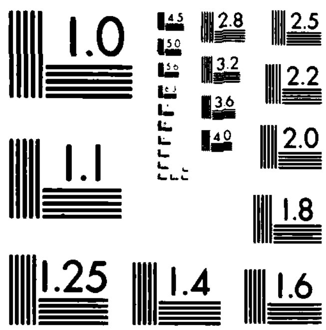

MICROCOPY RESOLUTION TEST CHART
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TABLE 35. ANALYSIS OF OCCIDENTAL DESALTED AND HYDROTREATED SHALE OIL, JP-8 FROM HYDROTREATED OIL, PARAHO SHALE OIL AND ARABIAN LIGHT BERRI DESALTED PETROLEUM OIL

	Light Berri Oil	Occidental Shale: Deashed Oil	Occidental Shale: HP Hydrotreated Oil	Occidental Shale: JP-8	Paraho Shale Oil
API Gr. at 60°F	35.4	22.9	32.3	45.1	19.8
Sp. Gr. at 60°F	0.8478	0.9165	0.8639	0.8012	0.9352
Bubble Pt. at 500 psig, °F	720	1056			
Distillation (D-1160), °F					
IBP	127	376	430	295	408
5%	225	467	469	314	471
10%	274	510	495	330	525
30%	420	621	581	359	670
50%	589	712	663	438	789
70%	782	820	760	474	889
87%	1083	953			1005
90%			958	512	
% Over	90	87	97	99	90
% Bottoms	10	13	3	--	10
Con. Carbon, wt-%	-	1.36	0.06	-	2.71
Nitrogen, wt-%	840 ppm	1.5	680 ppm	1.1 ppm	2.2
Bromine Number	1.2	23.6	1.3	-	34.7
Ash, wt-%	0.001	0.014	-	-	0.007
C_7 Insol., wt-%	0.55	0.34	0.06	-	0.47
Emission, ppm					
Fe	0.55	42	1.3	-	38
Mn	-	<0.2	-	-	-
Cr	-	0.21	-	-	-
Ni	2.4	6.7	0.25	-	2.2
Mo	-	1.6	<0.1	-	0.12
Cu	<0.1	<0.1	<0.1	-	0.18
H_2O, wt-%	323 ppm	0.05	-	-	<0.01
Arsenic, ppm	-	27.5	-	-	19
Sulfur, wt-%	1.34	0.64	0.012	282 ppm	0.70
Total O, wt-%	851 ppm	0.65	-	-	1.58
Carbon, wt-%	85.74	84.99	85.8	84.3	-
Hydrogen, wt-%	12.96	12.27	13.6	13.9	-
Diene Value	-	31.6	-	-	-

TABLE 36. EFFECT OF WIRE TEMPERATURE ON h AND dR_F/dt VALUES OF AGED OCCIDENTAL DESALTED SHALE OIL

Period	Temperature, °C Fluid	Temperature, °C Wire	Wire Temp. 1/K x 10^{-4}	h Original	h Final	dR_F/dt x 10^{-5}
			Run No. 35			
7	92.9	175.8	22.3	223.4	222.1	1.40
8	93.4	187.6	21.7	223.5	223.9	nil
9	93.4	211.2	20.7	227.9	225.0	1.45
10	93.4	235.6	19.7	226.7	222.9	2.52
11	93.4	264.2	18.6	223.1	220.8	2.24
12	93.4	294.6	17.6	218.6	213.1	4.43
13	93.4	327.9	16.6	212.2	204.1	6.08
14	93.4	365.9	15.7	201.5	194.5	6.70
15	93.4	406.8	14.7	191.2	178.8	12.9
16	93.4	458.6	13.7	174.8	155.6	26.7
17	93.9	526.4	12.5	153.1	137.4	30.5
			Run No. 37			
7	93.2	185.0	21.8	205.7	204.6	0
8	93.2	197.3	21.2	206.2	204.7	0.36
9	93.2	224.5	20.1	208.5	207.0	0.71
10	93.4	250.2	19.1	208.4	206.2	1.05
11	93.4	280.7	18.0	206.8	204.2	2.10
12	93.4	313.6	17.0	203.2	198.4	4.25
13	93.5	350.1	16.0	197.1	189.8	7.36
14	93.5	392.3	15.0	186.6	177.6	10.2
15	93.5	440.4	14.0	174.6	164.4	12.7
16	93.5	496.0	13.0	160.6	142.3	32.8
			Run No. 38			
7	92.0	182.4	21.9	208.6	208.6	0
8	92.0	194.4	21.3	210.3	210.3	0
9	92.0	220.2	20.2	214.3	212.6	0
10	92.0	246.0	19.2	213.6	212.3	0.74
11	92.0	275.9	18.2	212.0	210.7	1.70
12	92.0	307.8	17.2	209.4	205.7	2.67
13	92.5	341.9	16.2	204.7	199.8	4.50
14	92.5	380.1	15.3	197.0	190.9	6.13
15	92.5	421.1	14.4	188.8	181.9	6.89
16	92.7	466.4	13.5	179.2	172.2	8.19

TABLE 37. EFFECT OF WIRE TEMPERATURE ON h AND dR_F/dt VALUES OF AGED ARABIAN LIGHT BERRI PETROLEUM CRUDE OIL

Period	Temperature, °C Fluid	Wire	Wire Temp. 1/K x 10^{-4}	h Original	Final	dR_F/dt x 10^{-5}
			Run No. 33			
7	90.7	179.5	22.1	206.2	207.3	nil
8	91.1	190.6	21.6	209.8	210.7	nil
9	91.6	215.7	20.5	214.7	214.7	nil
10	91.6	240.1	19.5	214.9	214.7	nil
11	92.0	268.2	18.5	214.5	214.5	nil
12	92.0	298.0	17.5	212.0	206.6	4.16
13	92.1	333.7	16.5	203.4	194.8	7.10
14	91.6	375.7	15.4	190.4	182.2	6.96
15	91.8	421.5	14.4	177.1	168.1	11.26
16	91.8	473.0	13.4	163.5	155.8	11.26
			Run No. 36			
7	90.8	182.1	22.0	196.4	197.5	nil
8	90.8	193.2	21.4	201.6	199.9	nil
9	90.9	218.3	22.2	204.6	205.0	nil
10	91.1	242.8	19.4	205.8	205.8	nil
11	91.2	271.4	18.4	207.1	207.1	nil
12	91.4	300.0	17.4	206.9	205.5	1.18
13	91.7	330.9	16.6	204.8	200.5	3.81
14	91.7	365.6	15.7	198.9	193.8	5.00
15	91.8	403.6	14.8	191.3	181.7	8.24
16	91.8	449.0	13.8	178.9	171.8	9.05

TABLE 38. FOULING CHARACTERISTICS OF SHALE AND PETROLEUM PRODUCTS

Temperature, °C	°F	Occidental Shale 13 Mo	22 Mo	Light Berri 8 Mo	17 Mo	ALB-90 OS-10	ALB-70 OS-30	HPOS	Paraho 3 Mo	JP-8 from HPHOS
		Fouling Rate $dR_F/dt \times 10^{-5}$								
200	392	3.49	1.07*	1.32	1.55*	0.59*	0.41*	0.009*	28	0.5
225	437	4.75	1.51	2.27	2.04*	0.90*	0.68*	0.02*	35	0.7
250	482	5.94	2.08	3.26	2.62*	1.32*	1.08*	0.06*	43	1.1
275	527	7.27	2.77	4.80	3.28*	1.87*	1.65*	0.13*	52	1.58
300	572	8.75	3.61	6.67	4.03	2.58	2.42	0.27*	62	2.23
325	617	10.37	4.61	9.01	4.87	3.46	3.45	0.51*	72	3.01
350	662	12.12	5.76	11.86	5.79	4.53	4.76	0.94*	83	4.07
375	707	14.00	7.07	15.30	6.80	5.81	6.43	1.65	95	5.27
400	752	15.97	8.55	19.34	7.87	7.30	8.46	2.77	107	6.53
Activation Energy cal/mol		-4626	-6613	-8176	-5142	-7797	-9605	-18011	-4214	-8550

* = Calculated Values - Actual Values $dR_F/dt < 0.5 \times 10^{-5}$

ALB = Arabian Light Berri Petroleum Crude

OS = Occidental Shale Oil

HPHOS = High Pressure Hydrotreated Occidental Shale Oil

3 Mo. = Estimated Age of 3 Months

TABLE 39. EFFECT OF TEMPERATURE ON h AND dR_F/dt VALUES OF A 90:10 (BY WEIGHT) BLEND OF ARABIAN LIGHT BERRI DESALTED PETROLEUM CRUDE AND OCCIDENTAL SHALE OILS

Period	Temperature, °C Fluid	Wire	Wire Temp. $1/K \times 10^{-4}$	h Original	Final	dR_F/dt $\times 10^{-5}$
			Run No. 41			
7	91.3	178.7	22.1	209.2	208.7	nil
8	91.3	190.6	21.6	211.7	211.7	nil
9	91.6	215.6	20.5	214.5	214.2	nil
10	91.6	240.1	19.5	216.2	213.8	0.88
11	91.8	268.2	18.5	214.9	212.9	0.68
12	91.8	298.4	17.5	212.3	209.1	2.27
13	91.8	330.8	16.6	206.6	202.8	3.85
14	91.8	366.7	15.6	199.8	193.5	6.06
15	92.0	405.5	14.7	191.6	183.7	8.29
16	92.0	449.5	13.8	181.2	173.1	9.16
			Run No. 42			
7	90.7	178.0	22.2	213.6	213.6	nil
8	90.7	189.8	21.6	215.2	214.4	nil
9	90.9	215.0	20.5	217.3	216.6	nil
10	90.9	239.9	19.5	216.5	215.9	1.23
11	90.9	269.2	18.4	214.3	214.2	nil
12	91.1	299.1	17.5	212.6	211.3	1.78
13	91.3	331.8	16.5	207.6	202.4	3.52
14	91.6	367.9	15.6	200.7	188.1	10.71
15	91.6	415.5	14.5	184.7	174.1	10.51
16	91.6	464.9	13.6	171.1	166.0	8.06

TABLE 40. EFFECT OF TEMPERATURE ON h AND dR_F/dt VALUES
OF A 70:30 (BY WEIGHT) BLEND OF
ARABIAN LIGHT BERRI DESALTED PETROLEUM AND OCCIDENTAL DESALTED SHALE OILS

Period	Temperature, °C Fluid	Temperature, °C Wire	Wire Temp. $1/K \times 10^{-4}$	h Original	h Final	$dR_F/dt \times 10^{-5}$
			Run No. 39			
7	91.6	176.4	22.2	219.8	219.8	nil
8	91.8	187.9	21.7	220.8	220.8	nil
9	91.8	213.0	20.6	222.4	222.3	nil
10	91.8	237.1	19.6	222.2	222.0	nil
11	91.8	264.8	18.6	221.4	220.9	0.85
12	91.8	293.5	17.6	219.9	219.6	0.70
13	91.8	324.3	16.7	216.8	213.3	3.22
14	92.1	358.7	15.8	209.5	203.8	4.71
15	92.3	399.4	14.9	199.5	182.5	15.17
16	92.3	450.2	13.8	181.8	172.1	10.16
			Run No. 40			
7	91.3	178.4	22.2	211.9	213.8	nil
8	91.3	189.5	21.6	213.9	215.0	nil
9	91.8	214.1	20.5	218.7	218.2	nil
10	91.6	238.4	19.6	218.5	218.5	nil
11	91.6	266.0	18.6	218.1	218.1	nil
12	91.7	294.4	17.6	217.6	215.7	1.56
13	91.7	326.1	16.7	213.1	208.1	3.85
14	91.7	364.2	15.7	202.9	194.7	7.89
15	91.8	406.8	14.7	190.6	178.6	12.16
16	91.8	456.1	13.7	176.0	168.5	9.76

TABLE 41. EFFECT OF PROBE TEMPERATURE ON h AND dR_F/dt OF HIGH PRESSURE HYDROTREATED OCCIDENTAL SHALE OIL

Period	Temperature, °C Fluid	Temperature, °C Wire	Wire Temp. 1/K x 10^{-4}	h Original	h Final	dR_F/dt x 10^{-5}
			Run No. 47			
7	91.1	174.0	22.4	226.8	226.8	nil
8	91.6	184.8	21.8	231.0	231.0	nil
9	91.6	209.4	20.7	231.7	231.7	nil
10	91.6	232.9	19.8	231.9	231.9	nil
11	92.0	261.0	18.7	230.0	230.0	nil
12	92.0	288.5	17.8	229.0	229.0	nil
13	92.0	318.1	16.9	226.6	226.6	nil
14	92.5	348.8	16.1	223.8	223.8	nil
15	92.5	380.4	15.3	220.4	218.3	1.94
16	92.5	414.9	14.5	214.7	208.6	4.23
			Run No. 49			
7	90.7	183.1	21.9	193.4	193.4	nil
8	90.7	194.3	21.4	197.0	197.0	nil
9	90.7	219.6	20.3	201.0	201.0	nil
10	91.1	243.9	19.3	203.9	203.9	nil
11	90.7	270.4	18.4	206.1	206.1	nil
12	90.7	297.8	17.5	208.1	208.1	nil
13	90.7	328.8	16.6	205.2	205.2	nil
14	91.1	359.4	15.8	204.2	204.2	nil
15	92.0	390.1	15.1	203.9	201.9	1.97
16	92.0	425.1	14.3	199.5	193.9	4.70
17	91.6	466.1	13.5	190.5	181.8	9.07
18	91.6	515.9	12.7	177.3	171.8	8.71

TABLE 42. EFFECT OF WIRE TEMPERATURE ON h AND dR_F/dt OF JP-8 DERIVED FROM HIGH-PRESSURE HYDROTREATED OCCIDENTAL SHALE OIL

Period	Temperature, °C Fluid	Wire	Wire Temp. $1/K \times 10^{-4}$	h Original	Final	dR_F/dt $\times 10^{-5}$
			Run No. 64			
5	96.1	155.9	23.3	169.1	169.1	nil
6	96.2	178.2	22.2	179.1	180.4	nil
7	96.3	193.0	21.5	183.4	182.0	0.26
8	96.3	205.9	20.9	184.1	186.6	nil
9	96.4	232.7	19.8	188.2	188.4	nil
10	97.0	258.4	18.8	189.7	189.7	nil
11	97.5	287.4	17.8	191.7	190.0	1.62
12	98.2	319.7	16.9	189.8	186.1	3.20
13	98.4	353.9	16.0	155.5	152.1	4.35
14	98.6	389.8	15.1	181.7	177.6	4.15
			Run No. 65			
7	100.2	251.2	19.1	211.1	211.1	nil
8	100.5	280.5	18.1	210.2	208.4	1.81
9	100.5	311.7	17.1	207.6	205.0	2.46
10	100.5	344.5	16.2	203.1	198.1	3.29
11	100.5	380.0	15.3	197.3	193.2	3.98
12	100.8	417.3	14.5	191.8	186.9	4.67
13	100.8	456.7	13.7	184.9	174.0	11.74
14	100.8	504.2	12.9	174.2	160.2	16.75

TABLE 43. EFFECT OF TIME AT CONSTANT WIRE VOLTAGE ON h AND dR_F/dt OF PARAHO SHALE OIL

Period, hours	Temperature, °C Fluid	Temperature, °C Wire	Wire Temp. $1/K \times 10^{-4}$	h Original	h Final	dR_F/dt $\times 10^{-5}$
			Run No. 60			
0-3	92.4	183.8	21.9	234.8	189.2	33.6
3-6	92.4	201.1	21.1	188.2	168.5	20.3
6-9	92.4	211.6	20.6	167.1	153.5	18.0
9-12	92.3	219.8	20.3	153.1	141.4	17.7
12-15	92.4	227.8	20.0	140.7	130.8	16.6
15-18	89-95	240.0	19.5	127.5	119.8	19.7
18-21	89-95	245.3	19.3	121.6	116.7	17.0
21-24	92.3	248.6	19.2	116.1	112.1	14.0
0-24	92.4	183.8	21.9	234.8	112.1	19.4
			Run No. 61			
0-3	92.6	144.9	23.9	199.0	167.6	26.5
3-6	92.6	153.2	23.5	167.6	154.2	15.1
6-9	92.7	157.2	23.2	154.2	148.2	10.4
9-12	92.6	159.4	23.1	148.2	141.8	8.23
12-15	92.6	161.8	23.0	142.3	139.4	5.58
15-18	92.7	162.9	22.9	139.4	136.1	2.15
18-21	92.8	164.3	22.9	136.1	134.5	2.77
21-24	92.8	165.7	22.8	132.9	131.4	6.48
24-27	92.8	166.9	22.7	131.3	130.2	4.09
27-30	92.8	167.3	22.7	130.2	128.4	2.13
30-33	92.7	168.3	22.7	128.2	127.1	3.22
33-36	92.8	168.7	22.6	127.1	126.5	0.70
36-39	91.6-92.9	168.7	22.6	126.5	125.4	nil
39-42	92.7	169.8	22.6	124.6	124.2	nil
42-45	92.8	170.2	22.6	124.2	124.2	nil
45-48	92.8	170.2	22.6	124.2	122.6	3.65
48-51	92.9	170.6	22.5	122.6	122.8	nil
51-54	92.8	170.9	22.5	122.8	121.7	2.94
54-57	92.7	171.3	22.5	121.7	120.7	1.89
57-60	92.8	171.7	22.5	120.7	120.7	1.64
0-60	92.7	144.9	23.9	199.0	120.7	5.43

TABLE 44. EFFECT OF TEMPERATURE ON h AND dR_F/dt VALUES OF PARAHO SHALE OIL. NEW WIRE PROBE AT EACH NEW TEMPERATURE

Period	Temperature, °C		Wire Temp.	h		dR_F/dt
	Fluid	Wire	$1/K \times 10^{-4}$	Original	Final	$\times 10^{-5}$
58	92.0	143.0	24.0	203.4	191.5	11.9
61	92.5	145.8	23.9	199.0	167.6	26.5
62	91.1	148.8	23.7	179.8	164.2	17.4
56	92.5	165.2	22.9	206.8	188.0	15.8
60	92.4	183.8	21.9	234.8	189.2	33.6
55	91.8	186.8	21.8	226.9	202.6	16.8
54	91.8	188.7	21.7	220.6	194.5	18.9
53	91.6	190.9	21.5	206.6	170.1	32.8
57	92.2	213.0	20.6	224.8	194.8	25.1
59	91.6	235.8	19.6	223.2	162.5	52.6

TABLE 45. EFFECT OF PROPRIETARY ANTIFOULANT ON FOULING RATE AND h VALUES OF PARAHO SHALE OIL

Period	Temperature, °C		Wire Temp.	h		dR_F/dt
	Fluid	Wire	$1/K \times 10^{-4}$	Original	Final	$\times 10^{-5}$
10	92.2	173.0	22.4	235.4	237.1	nil
11	92.6	183.3	21.9	236.5	241.9	nil
12	92.3	206.2	20.9	241.2	245.8	nil
13	92.3	228.2	20.0	244.6	228.8	11.97
14	92.5	263.6	18.6	225.6	203.7	17.5

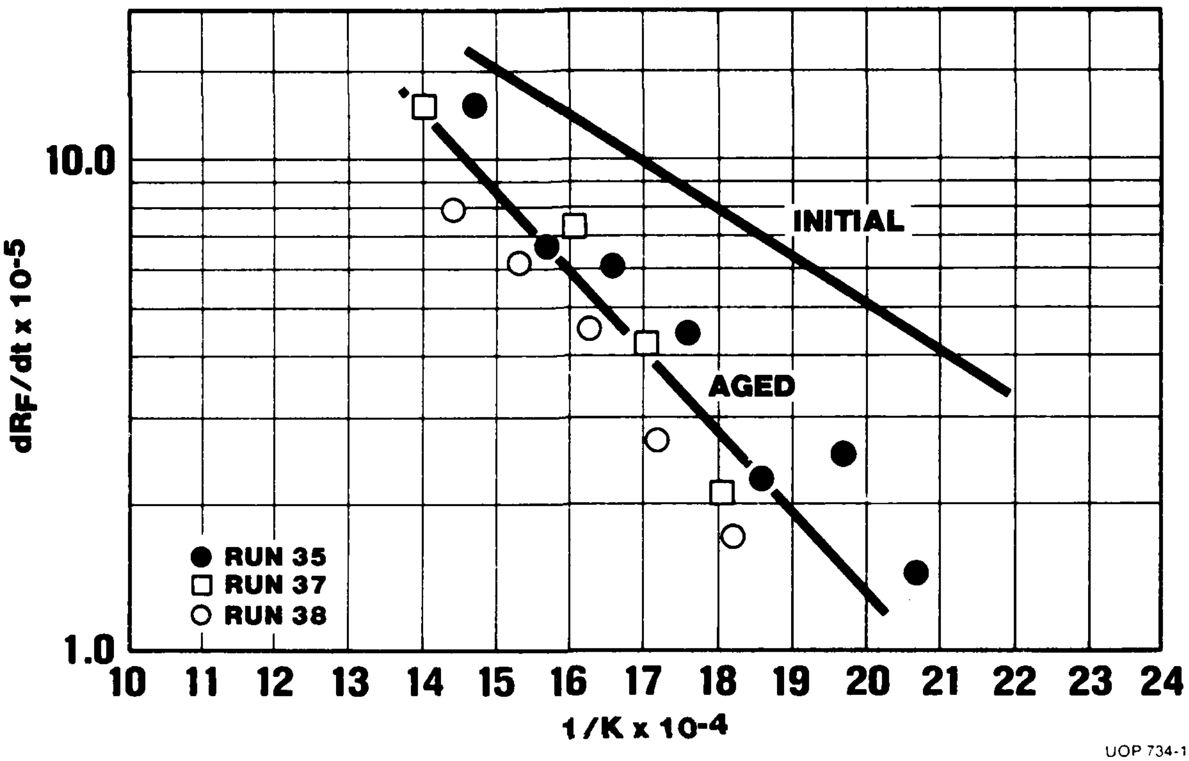


FIGURE 15

EFFECT OF TEMPERATURE AND AGING ON FOULING RATE OF DESALTED OCCIDENTAL SHALE OIL

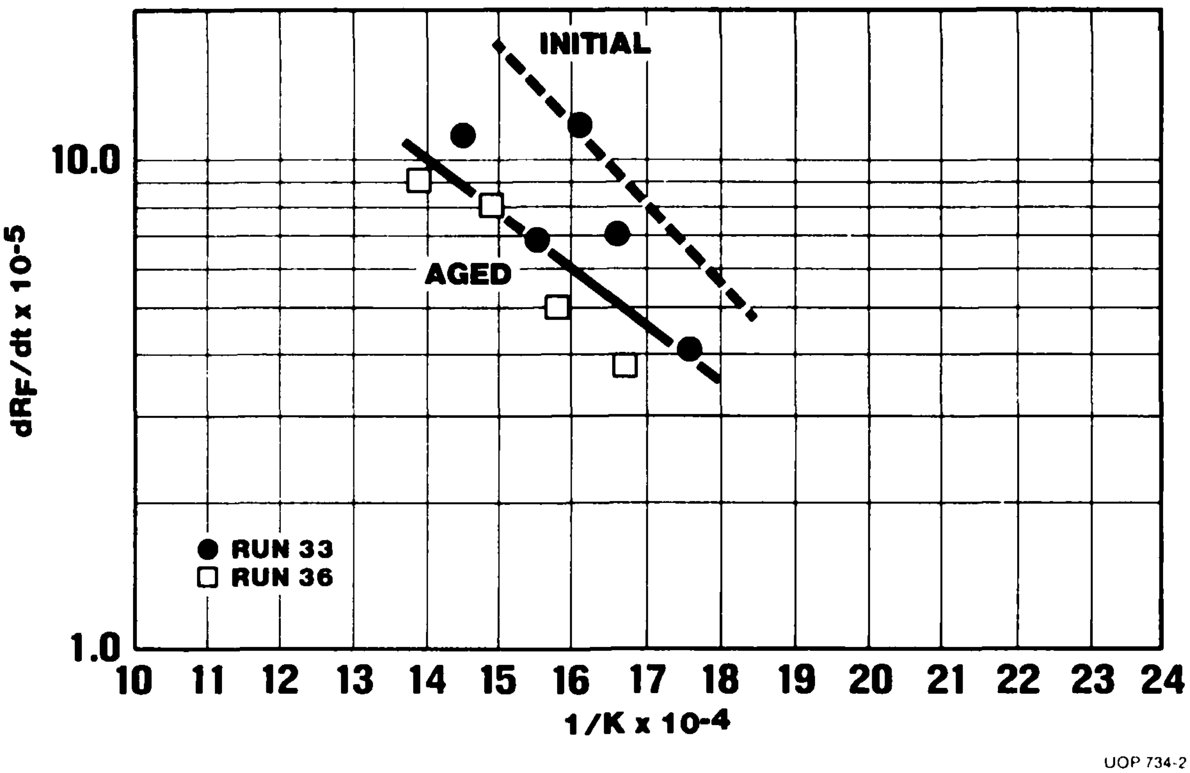
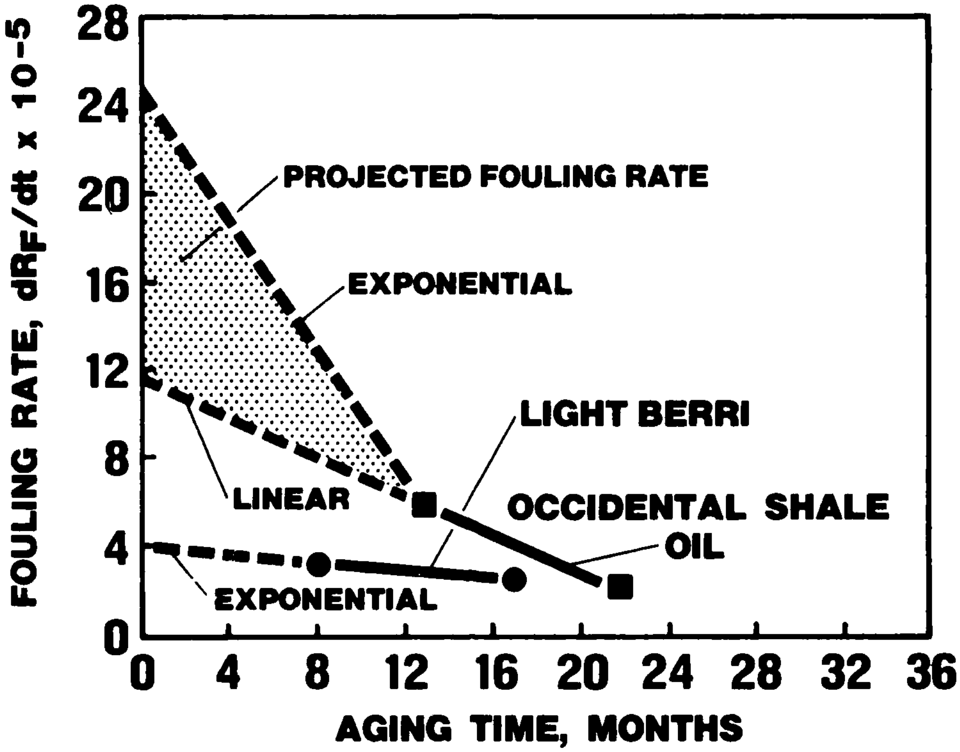


FIGURE 16

EFFECT OF TEMPERATURE AND AGING ON FOULING RATE OF DESALTED ARABIAN LIGHT BERRI PETROLEUM OIL



UOP 710-9
UOP 734-3

FIGURE 17

EFFECT OF AGING ON FOULING RATE

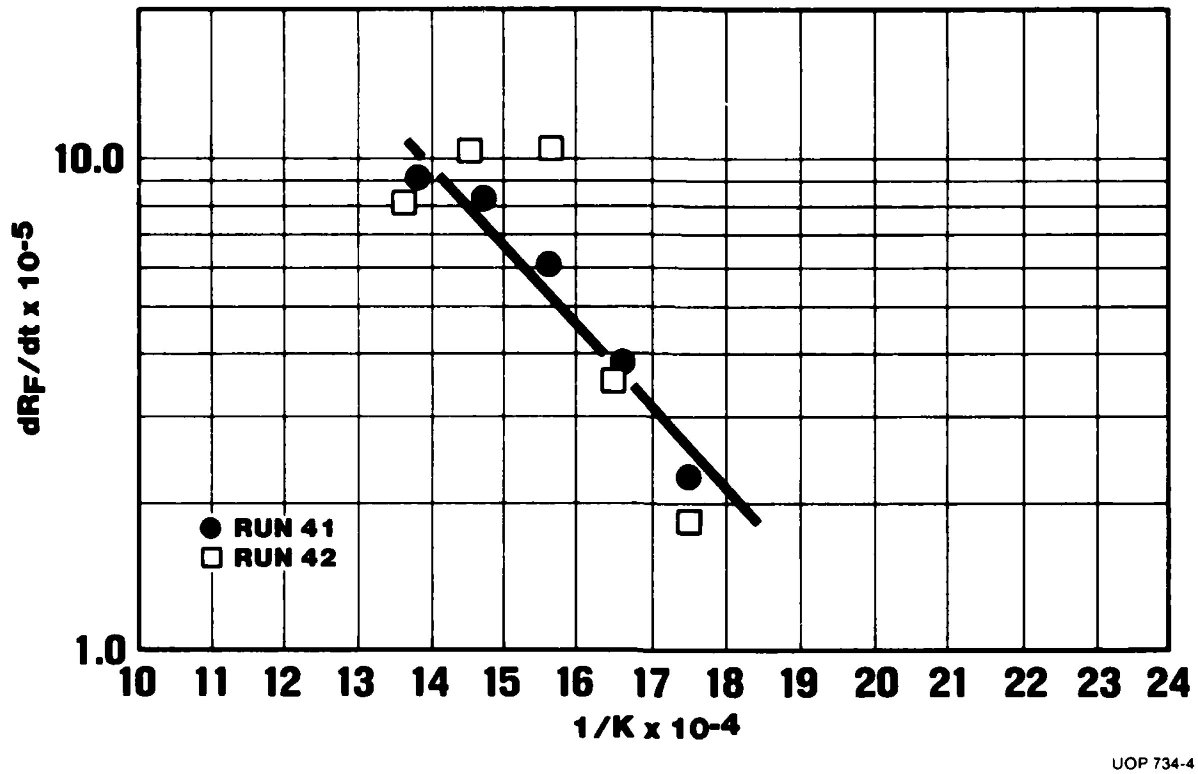


FIGURE 18

FOULING RATE OF 1:9 BLEND OF DESALTED OCCIDENTAL SHALE AND ARABIAN LIGHT BERRI PETROLEUM OILS

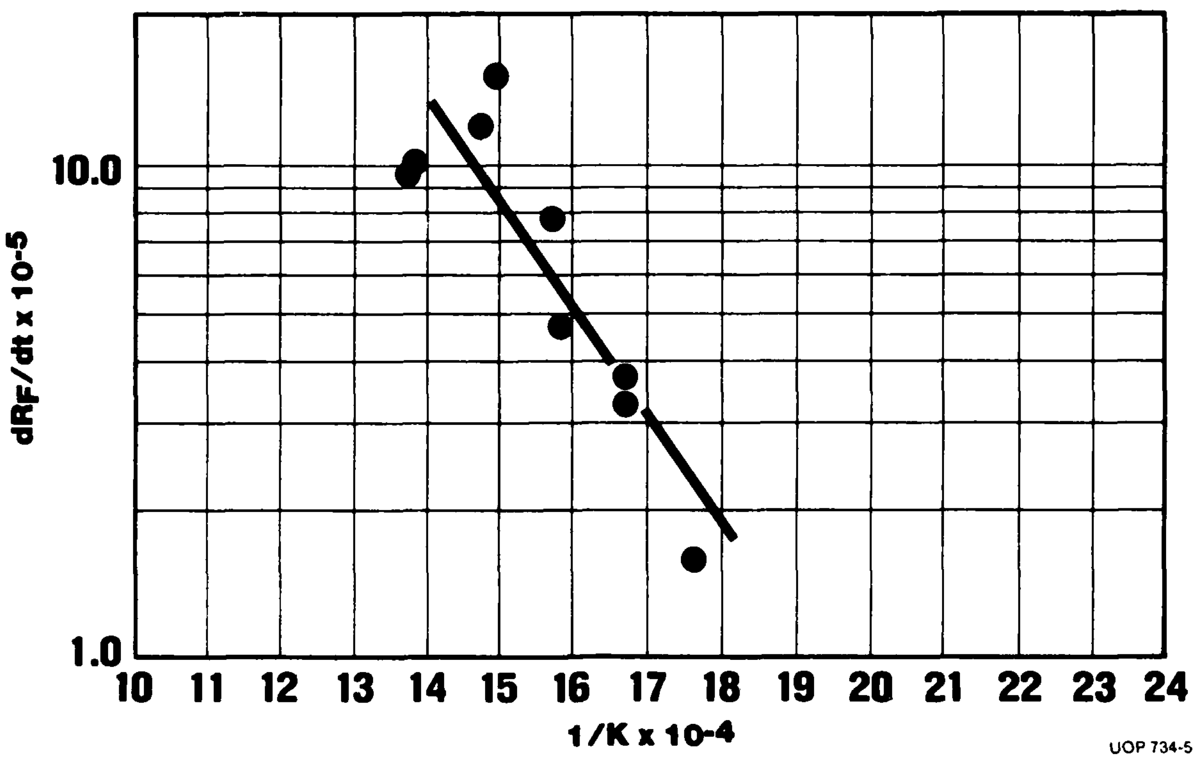


FIGURE 19

FOULING RATE OF 3:7 BLEND OF DESALTED OCCIDENTAL SHALE AND ARABIAN LIGHT BERRI PETROLEUM OILS

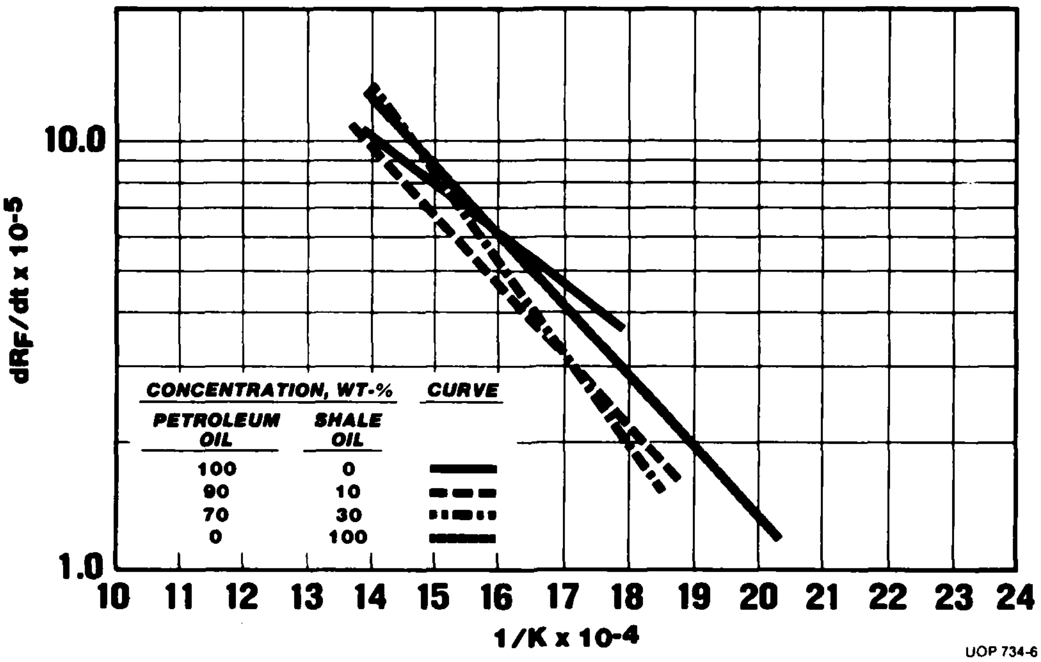


FIGURE 20

EFFECT OF BLENDING ON FOULING RATE

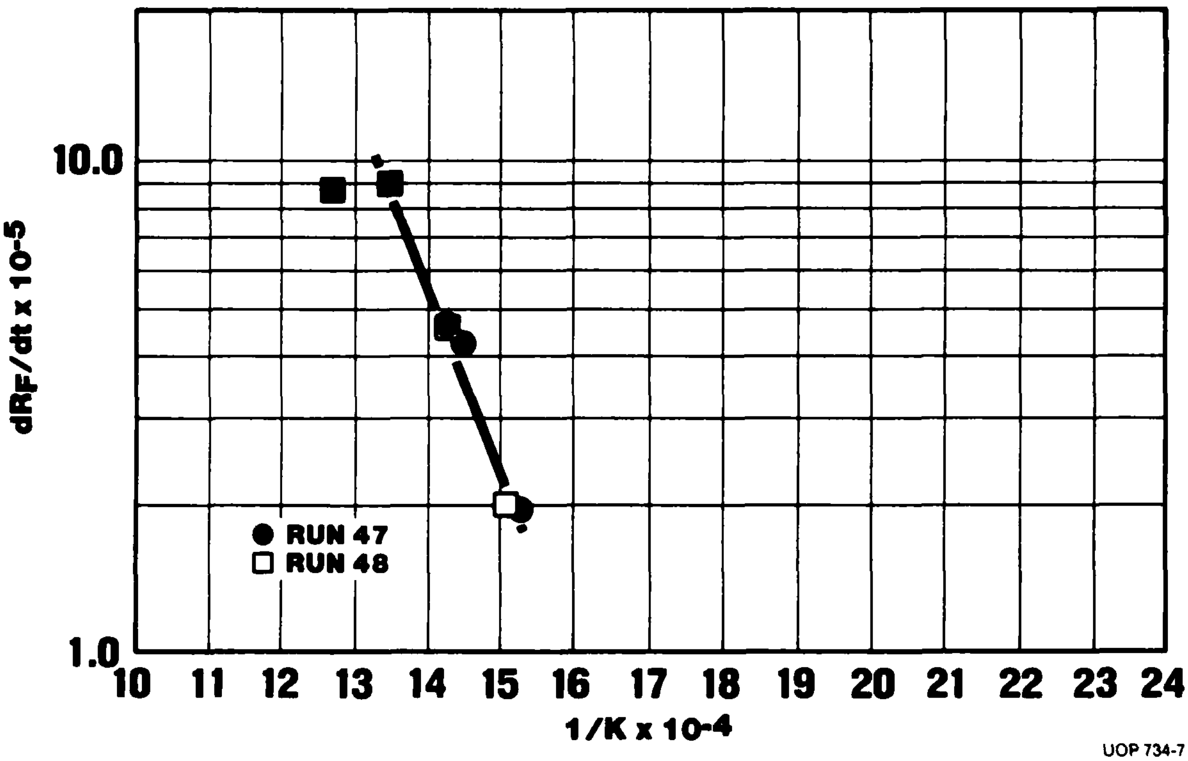


FIGURE 21

FOULING RATE OF HYDROTREATED OCCIDENTAL SHALE OIL

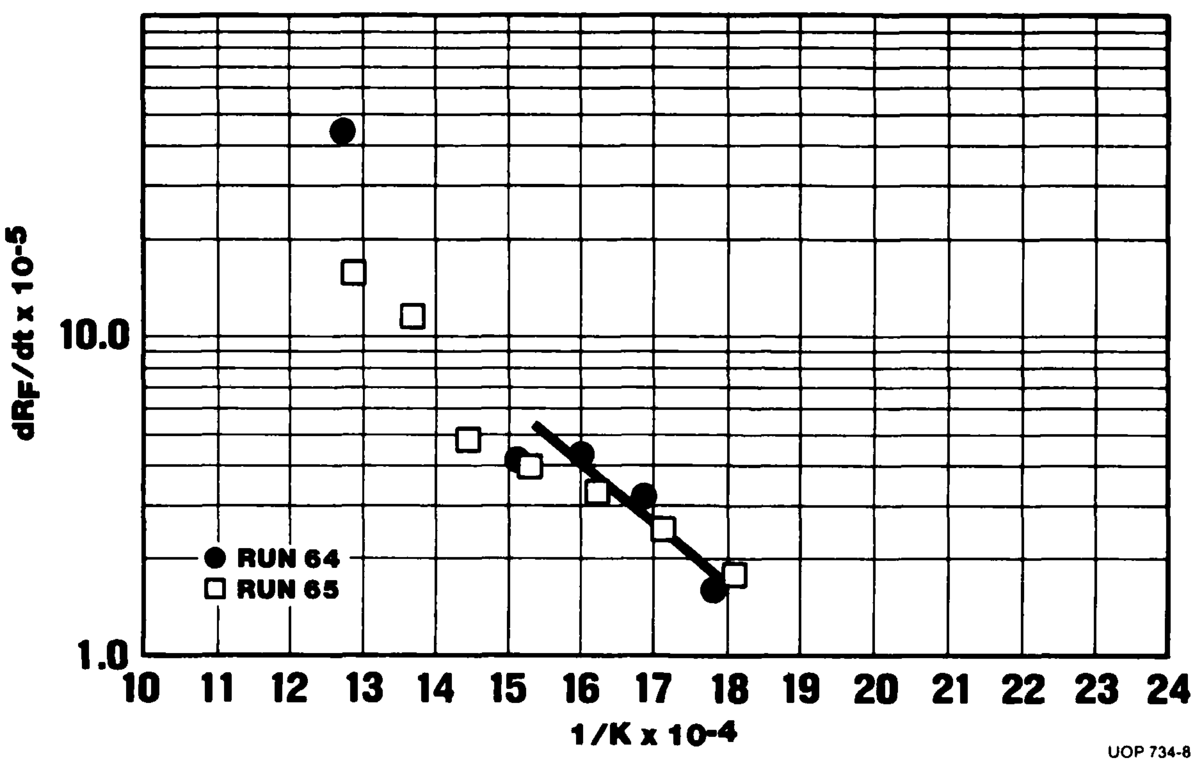


FIGURE 22

FOULING RATE OF JP-8 FUEL FROM HYDROTREATED SHALE OIL

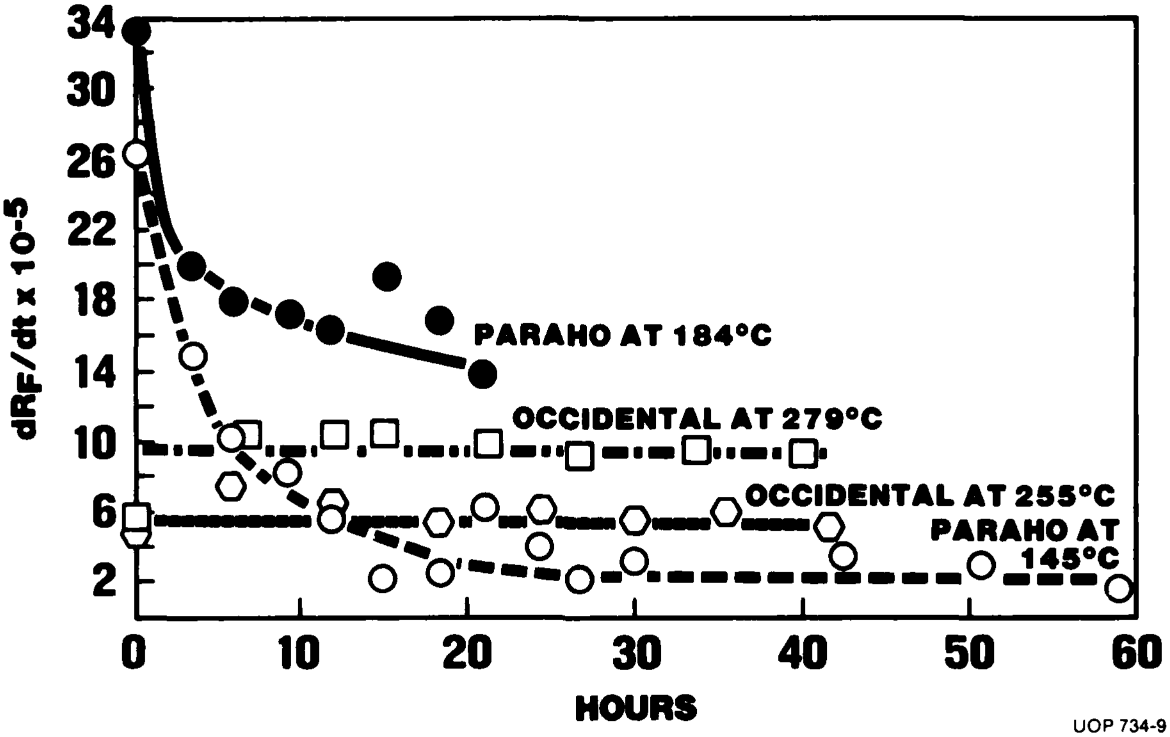


FIGURE 23

FOULING RATES OF DESALTED OCCIDENTAL AND PARAHO SHALE OILS

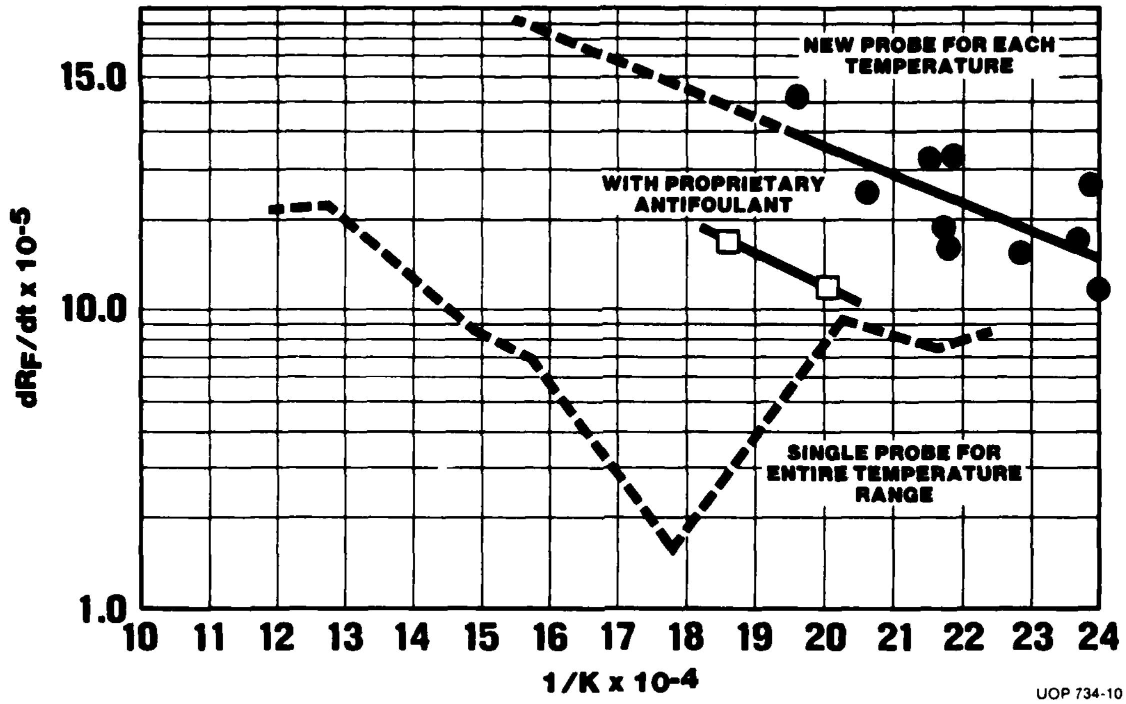


FIGURE 24

FOULING RATE OF PARAHO SHALE OIL

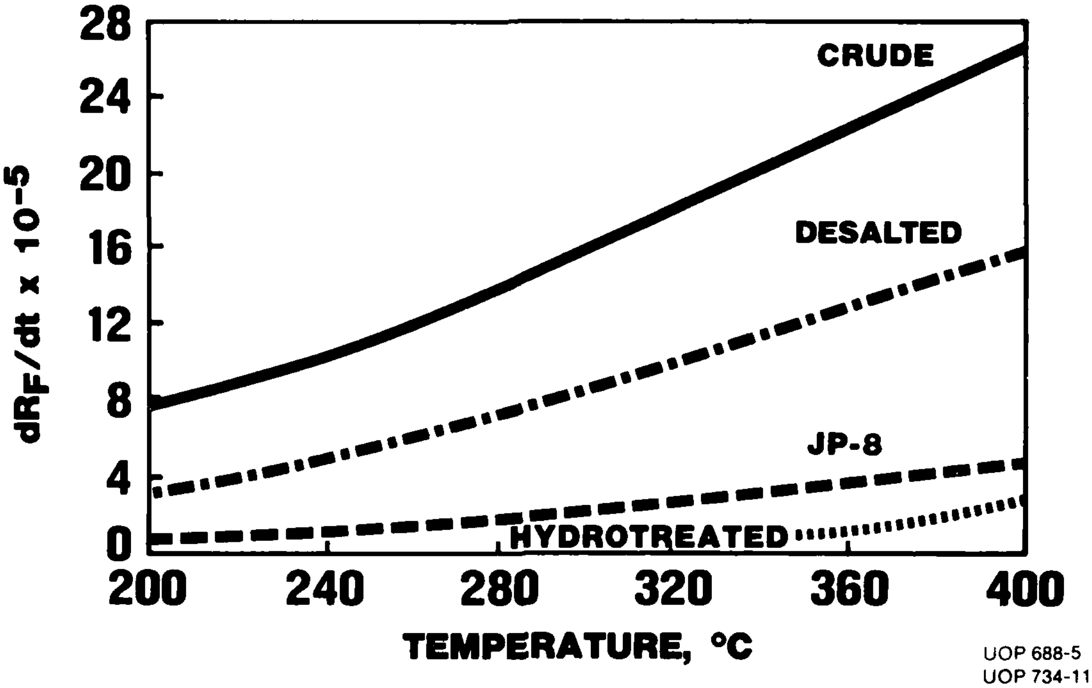


FIGURE 25

EFFECT OF TEMPERATURE ON THE FOULING RATE OF OCCIDENTAL SHALE OIL DERIVED FEEDS

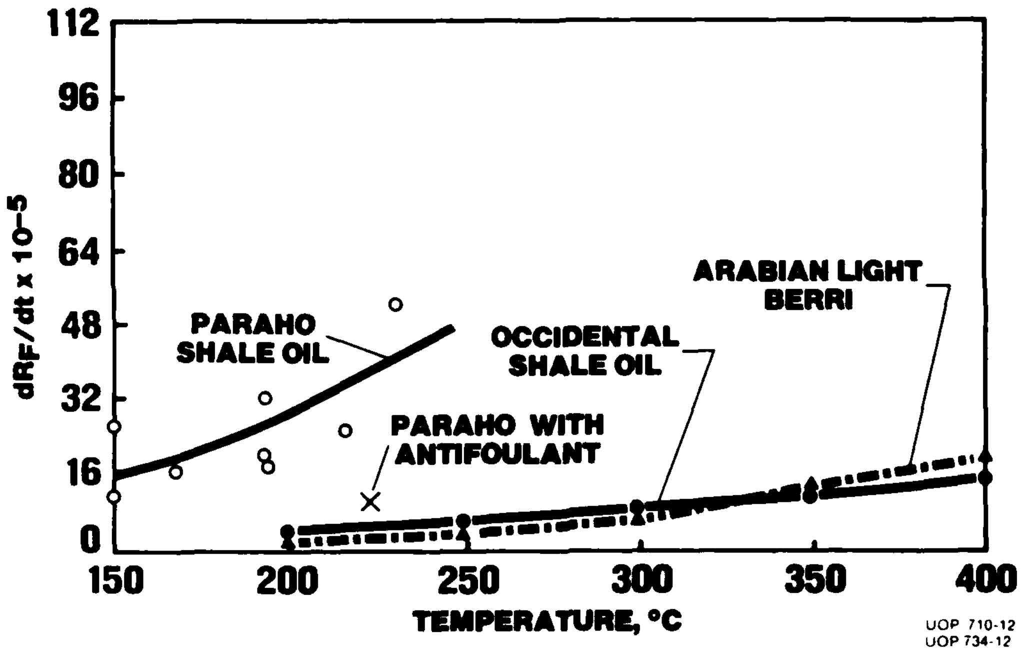


FIGURE 26

EFFECT OF TEMPERATURE ON FOULING RATE OF SHALE AND PETROLEUM OILS

SECTION VII

SHALE OIL/PETROLEUM OIL STABILITY/COMPATIBILITY STUDY

Introduction

Background

Oil shale represents an enormous potential reserve of energy for the United States. Conversion of oil shale to liquid hydrocarbons suitable as substitutes for transportation and heating fuels could augment the United States' reserves. Various pyrolysis processes are presently under development to produce liquid hydrocarbons from oil shale. They include surface processes and "in-situ" processes. Several processes have progressed beyond the small bench scale of the laboratory to the demonstration stage, and now have the capability of producing relatively large quantities of hydrocarbon liquids. Characterization of the liquid generated from these processes is an important consideration in direct utilization or upgrading processes. The immediate and best utilization of hydrocarbon liquids produced from demonstration plants and commercial prototypes may be blending them with petroleum crude oils or fractions thereof and processing the blends in existing refineries.

Objectives

The objectives of this study were to determine the stability of primary shale oils and treated products and the compatibility/stability of primary shale oils and treated products with petroleum crude oil. The stability of shale oils and treated products in storage and use is of concern to refiners and users. Whereas many studies have been made on the stability of petroleum liquids, stability of shale oils and treated products have been limited by unavailability of shale oils. Their resistances to chemical change and physical disintegration in storage is not well known. The compatibility of shale oils and treated products with petroleum crude oil is also of concern. The compatibility of shale oils and treated products with petroleum crude oil is an important consideration in their blending, particularly with respect to co-processing shale oil/petroleum crude oil in existing refineries. The resulting blends should form a homogeneous mixture that neither separates nor is altered by chemical interaction. The physical and chemical properties of the blend should not be adversely affected.

Outline of Program

The program involved the stability study of primary shale oil and treated products derived therefrom and the compatibility/stability of primary shale oils and treated products derived therefrom with petroleum crude oil.

The primary shale oils selected were a raw Paraho shale oil and a raw Occidental shale oil. The crude oil selected was a heavy Arabian crude. Treated shale oils were derived from single-stage and two-stage hydrotreatment of the primary shale oils. Compatibility/stability studies of the shale oil/crude oil blend were conducted on blends consisting of 30 volume percent shale oil. The primary shale oils, treated products and petroleum crude oil were deoxygenated and inspected before the blending and subsequent stability testing.

Compatilibity and Stability Studies

Sources and Properties of Primary Samples

Primary Shale Oils -- Paraho shale oil produced by direct fired retort and Occidental shale oil produced by in-situ retorting were selected for study. The Paraho shale oil assigned for work under Phase II of the contract was received in March, 1979. It was from the 100,000 barrels of crude Paraho shale oil produced by Paraho Development Corporation over the three-year period from 1976 to 1978. The raw Paraho shale oil was desalted and dewatered. Inspections are given in Table 46. The Occidental shale oil, also processed under the aforementioned contract, was received in April, 1979. It was from the underground Room 6 retort using Occidental Petroleum Company's Modified In-Situ retorting process.

The raw Occidental shale oil was desalted and dewatered. Inspections are given in Table 46.

Crude Oil -- The foreign crude selected to represent typical Gulf Coast processing status was a heavy Arabian crude. Inspections are given in Table 46.

Treatment and Properties of Hydrotreated Shale Oils

Shale Oils -- Shale oils have unique characteristics relative to conventional crude petroleum oil. Unusually high arsenic and iron levels, high pour point and viscosity, a high unsaturates concentration, and a significant solids (ash) content make conventional front-end refining techniques unusable without proper pretreatment. To prepare the shale oil for the primary conversion step -- hydrocracking to jet and other fuels -- two stages of hydrotreatment were selected. The stability of the hydrotreated products and the stability/compatibility of petroleum crude oils blends were studied.

First-Stage Hydrotreatment -- The desalted Paraho shale oil and the desalted Occidental shale oil were processed in a first-strage hydrotreater to provide for removal of certain contaminants and stabilization of the raw shale oil, to allow high severity hydrotreatment and subsequent conversion operations. Inspections are given in Table 46.

Second-Stage Hydrotreatment -- The Paraho and Occidental first-stage hydrotreated products were processed in a second-stage hydrotreater at higher severity to reduce the high levels of impurities such as nitrogen and oxygen to acceptable levels for the primary conversion step -- hydrocracking to jet and other fuels. Inspections are given in Table 46.

Experimental Procedures

The preparation and analysis of samples for stability and compatibility testing are described in Appendicies A.1 and A.2. The stability tests selected for study were the Three Months 110°F Dark Storage Fuel Oil Stability Test (See Appendix A.3), the E. I. DuPont de Nemours and Co.

300°F Accelerated Fuel Oil Stability Test (1) and the ASTM No. 2274-74 Oxidation Stability of Distillate Fuel Oil Test (2). These tests are applicable to petroleum distillate fuels and were modified to permit stability testing of shale oils, petroleum crude oils and blends thereof (See appendices A.4, A.5 and A.6).

Results and Discussion

Stability Studies

Stability was assessed by measuring formation of adherent insolubles and changes in heptane insolubles, toluene insolubles and viscosity. The results obtained are summarized in Tables 47 and 48 and Figures 27 through 30.

Adherent Insoluble Formation -- The samples show relatively good stability with respect to adherent insoluble formation with the possible exception of the 30 volume percent raw Paraho shale oil/heavy Arabian crude blend which had adherent gum values of 2.1 mg/100 mL in the three-months storage test and 10.6 mg/100 mL in the ASTM D 2274-74 test. The other adherent gum values were less than 1 mg/100 mL in the three-month storage test.

C_7 Insoluble Stability -- The second-stage hydrotreated Paraho shale oil and the first- and second-stage Occidental shale oils were stable with respect to C_7 insolubles.

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(1) Petroleum Laboratory Method No. F21-61, "300°F Accelerated Fuel Oil Stability Test", E.I. Dupont de Nemours and Company, Inc., Wilmington, Delaware, December, 1962.

(2) Annnual Book of Standards, Part 24, P. 296, 1977; American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

The C_7 insolubles of the heavy Arabian crude, the raw and first-stage hydrotreated Paraho shale oil and raw Occidental shale oil increased after stability testing, indicating some measure of instability with respect to C_7 insolubles. The heavy Arabian crude had the highest increase indicating it was the most unstable. Next were the raw Paraho and raw Occidental shale oils which had similar increases. The first-stage hydrotreated Paraho had the lowest increase. Stability with respect to C_7 insolubles improved with the degree of hydrotreatment.

Blending of the raw shale oil with heavy Arabian crude decreases stability with respect to C_7 insolubles as evidenced by the magnitude of the increase in the C_7 insolubles after the three-month storage and the ASTM D 2274-74 test. Blending of the first- and second-stage hydrotreated shale oil with the heavy Arabian crude improves stability with respect to C_7 insolubles as evidenced by the decrease in the magnitude of the increase. Stability of the blends improves with the degree of hydrotreatment.

Viscosity Stability -- The second-stage hydrotreated Paraho shale oil and Occidental shale oil were stable with respect to viscosity. The viscosity of the heavy Arabian crude, raw and first-stage hydrotreated Paraho shale oil, and raw and first-stage hydrotreated Occidental shale oil increased after stability testing, indicating some measure of instability. The heavy Arabian crude had the highest increase indicating it was the most unstable. Next were the raw Paraho and Occidental shale oils which had similar increases. The lowest increases were obtained by the first-stage hydrotreated Paraho and first-stage hydrotreated Occidental shale oil which had similar increases. Stability with respect to viscosity improves with the degree of hydrotreatment. Blending of the heavy Arabian crude oil with the shale oils improves stability with respect to viscosity. Stability of the blends improves with the degree of hydrotreatment.

Toluene Insoluble Stability -- All samples show good stability with respect to toluene insolubles.

Compatibility Studies

The compatibility of the blends was determined by comparing the experimental values of viscosity, C_7 insolubles and toluene insolubles of the blend to calculated values. The calculated values of viscosity were determined from viscosity blending charts (3, 4). The calculated values of C_7 insolubles and toluene insolubles were determined from the amount of insolubles present in the original samples. The results obtained are summarized in Table 49. Good agreement was obtained between the calculated and experimental values in all the tests indicating that all of the blends of 30 volume percent shale oil/heavy Arabian crude oil are compatible.

Conclusions

The raw shale oils and hydrotreated products were found to be compatible with the heavy Arabian crude oil.

The raw shale oils, hydrotreated products and heavy Arabian crude showed good stability with respect to toluene insolubles and adherent insolubles.

The second-stage hydrotreated shale oils were found to be stable with respect to C_7 insolubles and viscosity.

The first-stage hydrotreated Occidental shale oil was found to be stable with respect to C_7 insolubles.

The heavy Arabian crude showed some measure of instability with respect to C_7 insolubles and viscosity and was the most unstable of the materials tested.

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(3) UOP Calculation Charts -- RE Chart I-4.

(4) "Refutas" Viscosity-Temperature Chart Designed by C. I. Kelly, Copyright BAIRO and TATLOCK (London), Ltd.

The raw shale oils showed some measure of instability with respect to C_7 insolubles and viscosity but less than the heavy Arabian crude.

The first-stage hydrotreated Paraho shale oil showed some measure of instability with respect to C_7 insolubles and viscosity but less than the raw shale oil.

The first-stage hydrotreated Occidental shale oil showed some measure of instability with respect to viscosity but less than the raw shale oil.

Stability with respect to C_7 insolubles and viscosity improves with increased hydrotreatment.

Blending of the shale oils with heavy Arabian crude improves stability with respect to viscosity.

Blending of the raw shale oils with heavy Arabian crude decreases stability with respect to C_7 insolubles.

Blending of the first- and second-stage hydrotreated shale oil with the heavy Arabian crude improves stability with respect to C_7 insolubles. Stability of blends with respect to C_7 insolubles and viscosity improves with increased hydrotreatment. Instability reflected in the shale oil/petroleum crude oil blends is accounted for to a great extent by the instability of the petroleum crude oil and should have no adverse effects in co-processing.

The data obtained were derived from shale oils that were stored for two to four years before the compatiblity and stability tests were conducted and may not be representative of data derived from fresh commercial samples.

TABLE 46. INSPECTION OF OILS

Name	Heavy Arabian Crude	Paraho Shale Oil			Occidental Shale Oil		
		Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated	Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated
API Gravity at 60°F	26.4	25.2	30.3	33.5	22.5	26.2	32.2
Specific Gravity at 60°F	0.8961	0.9303	0.9111	0.8576	0.9188	0.8973	0.8644
Distillation (D-1160), °F							
IBP	138	372	390	344	399	422	356
5%	189	450	471	438	479	508	450
10%	290	500	517	471	512	538	488
20%	420	585	590	521	572	589	532
30%	518	665	651	574	623	631	570
40%	626	728	710	620	677	672	615
50%	735	784	760	670	729	718	660
60%	851	840	810	721	775	767	710
70%	971	888	861	765	822	812	760
80%	(76) 1039	950	919	821	878	872	810
90%		1025	(95) 1043	(EP) 1009	960	(94) 1010	(EP) 979
% Over	76.0	90.0	95.0	99.0	90.0	94.0	97.0
% Bottoms	24	10.0	5.0	1.0	10.0	6.0	3.0
Carbon, wt-%	80.88	84.6	85.28	85.93	84.59	85.02	85.73
Hydrogen, wt-%	11.22	11.4	12.05	12.40	12.42	12.60	13.01
Oxygen, wt-%	0.93	1.76	0.60	0.26	1.55	0.52	0.28
Sulfur, wt-%	2.97	0.71	0.0746	0.00323	0.68	0.0261	< 0.03
Nitrogen, wt-%	0.17	2.19	1.90	0.06	1.42	1.09	0.09
C_7 Insolubles, wt-%	4.67	0.44	0.14	0.01	0.26	0.01	0.01
Toluene Insolubles, wt-%	< 0.01	0.01	< 0.01	0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	118.5	213	156.0	54.2	186.7	124.6	60.1
Viscosity at 100°F, cSt	24.80	45.72	33.23	8.633	39.98	26.20	10.35
Steam Jet Gum, mg/100 mL	35,875.0	26,463.0	22,129.0	5,668.1	21,314.8	16,940.5	7,823.5
Bromine Number	2.4	30.2	15.8	0.8	19.4	7.8	1.9
Nickel, ppm	13	3.5	3.0	< 0.1	8.8	3.2	< 0.1
Vanadium, ppm	47	0.5	0.5	< 0.1	0.5	< 0.2	< 0.2
Iron, ppm	2.8	108	13	< 0.3	53	14	< 0.1
Arsenic, ppm	< 1	30	< 1	< 1	28	< 1	< 1
Conradson Carbon, wt-%	7.98	2.35	1.57	0.01	1.05	0.44	0.03

TABLE 47. PARAHO SHALE OIL-PETROLEUM OIL

Compatibility/Stability Study

Name	Heavy Arabian Crude	30% Paraho Shale Oil/ 70% Heavy Arabian Crude			Paraho Shale Oil		
		Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated	Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated
Initial Analysis:							
C_7 Insolubles, wt-%	4.67	3.23	3.24	3.30	0.44	0.14	0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	0.01	< 0.01	0.01	< 0.01	0.01
Viscosity at 100°F, SUS	118.5	130.6	124.5	86.9	213	156	54.2
Stability Test Analysis:							
Du Pont F-21-61							
C_7 Insolubles, wt-%	5.92	3.38	3.28	3.60	0.40	0.2	< 0.01
Toluene Insolubles, wt-%	0.07	0.01	0.01	< 0.01	< 0.01	0.01	0.01
Viscosity at 100°F, SUS	190.9	178.9	162.1	111.5	268	183.7	56.3
D-2274 16-hr Heat Treatment							
C_7 Insolubles, wt-%	6.23	5.17	4.23	4.19	1.70	0.79	0.02
Toluene Insolubles, wt-%	< 0.01	0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	214	246	194.3	115.9	325	205	55.4
Adherent Gum, mg/100 mL	1.2	10.6	2.2	0.9			
3-months Dark Storage, 110°F							
C_7 Insolubles, wt-%	6.07	4.48	4.12	4.14	0.97	0.29	0.01
Toluene Insolubles, wt-%	0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	381	358	286	115.4	311	171	55.5
Adherent Gum, mg/100 mL	0.5	2.1	0.3	0.2	0.5	0.8	0.8

TABLE 48. OCCIDENTAL SHALE OIL/PETROLEUM OIL

Compatibility/Stability Study

Name	Heavy Arabian Crude	30% Occidental Shale Oil/ 70% Heavy Arabian Crude			Occidental Shale Oil		
		Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated	Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated
Initial Analysis:							
C_7 Insolubles, wt-%	4.67	3.21	3.00	3.28	0.26	0.01	0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	0.02	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	118.5	132.5	115.6	89.7	186.7	124.6	60.1
Stability Test Analysis:							
Du Pont F-21-61							
C_7 Insolubles, wt-%	5.92	3.38	3.39	3.51	0.50	0.40	0.01
Toluene Insolubles, wt-%	0.07	< 0.01	0.01	< 0.01	0.01	0.01	0.01
Viscosity at 100°F, SUS	190.9	169.7	146.7	107.9	210	135	63.6
D-2274 16-hr Heat Treatment							
C_7 Insolubles, wt-%	6.23	4.95	3.94	4.17	3.18	0.11	< 0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01	< 0.01
Viscosity at 100°F, SUS	214	209	169.5	119.4	260	140.1	62.2
Adherent Gum, mg/100 mL	1.2	2.4	0.4	1.7		0.9	1.1
3-months Dark Storage, 110°F							
C_7 Insolubles, wt-%	6.07	4.68	3.97	4.17	0.88	0.03	< 0.01
Toluene Insolubles, wt-%	0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Viscosity at 100°F, SUS	381	329	244	163.5	221	131.6	59.7
Adherent Gum, mg/100 mL	0.5	0.9	0.3	0.3	0.7	0.1	0.2

TABLE 49. SHALE OIL COMPATIBILITY/STABILITY STUDY

Comparison of Analyzed and Calculated Values for Shale Oil and Petroleum Blends

Shale Oil Component in Blend	Analytical cSt Viscosity	Calculated cSt Viscosity RE I-4	Calculated cSt Viscosity Refutas
30 Vol-% Raw Paraho Shale Oil	27.54	29.2	29.66
30 Vol-% Paraho Shale Oil First-Stage Hydrotreated	25.17	26.9	27.03
30 Vol-% Paraho Shale Oil Second-Stage Hydrotreated	17.38	17.5	17.59
30 Vol-% Raw Occidental Shale Oil	27.97	28.0	28.55
30 Vol-% Occidental Shale Oil First-Stage Hydrotreated	24.15	25.2	25.2
30 Vol-% Occidental Shale Oil Second-Stage Hydrotreated	18.06	18.8	18.73

	Analytical		Calculated	
	C_7 Insol., Wt-%	Toluene Insol., Wt-%	C_7 Insol., Wt-%	Toluene Insol., Wt-%
30 Vol-% Raw Paraho Shale Oil	3.23	<0.01	3.36	<0.01
30 Vol-% Paraho Shale Oil First-Stage Hydrotreated	3.24	0.01	3.29	<0.01
30 Vol-% Paraho Shale Oil Second-Stage Hydrotreated	3.30	<0.01	3.31	<0.01
30 Vol-% Raw Occidental Shale Oil	3.21	<0.01	3.32	<0.01
30 Vol-% Occidental Shale Oil First-Stage Hydrotreated	3.00	0.02	3.27	<0.01
30 Vol-% Occidental Shale Oil Second-Stage Hydrotreated	3.28	<0.01	3.31	<0.01

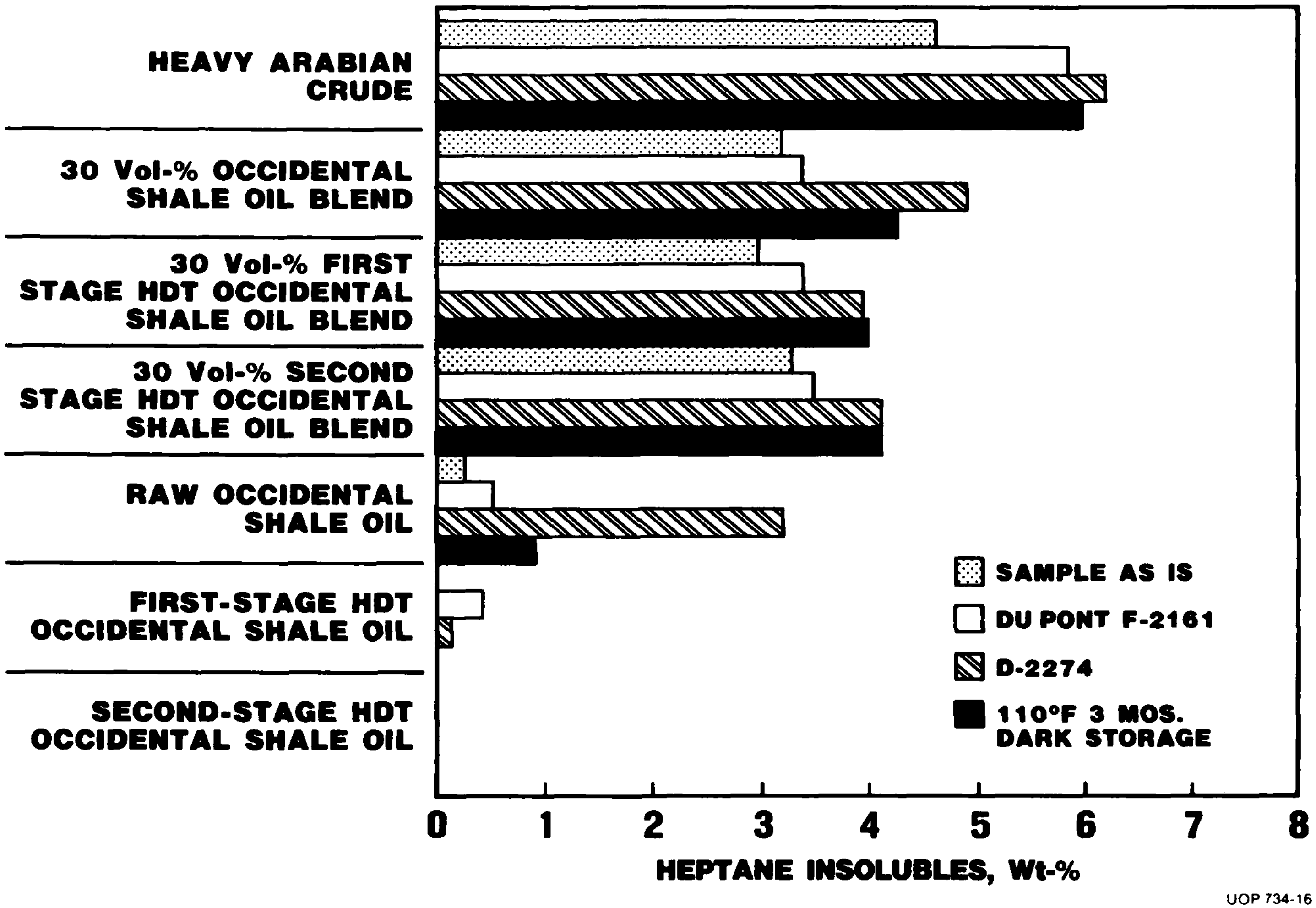

FIGURE 27

EFFECT OF STORAGE ON HEPTANE INSOLUBLES OCCIDENTAL SHALE OIL STUDY

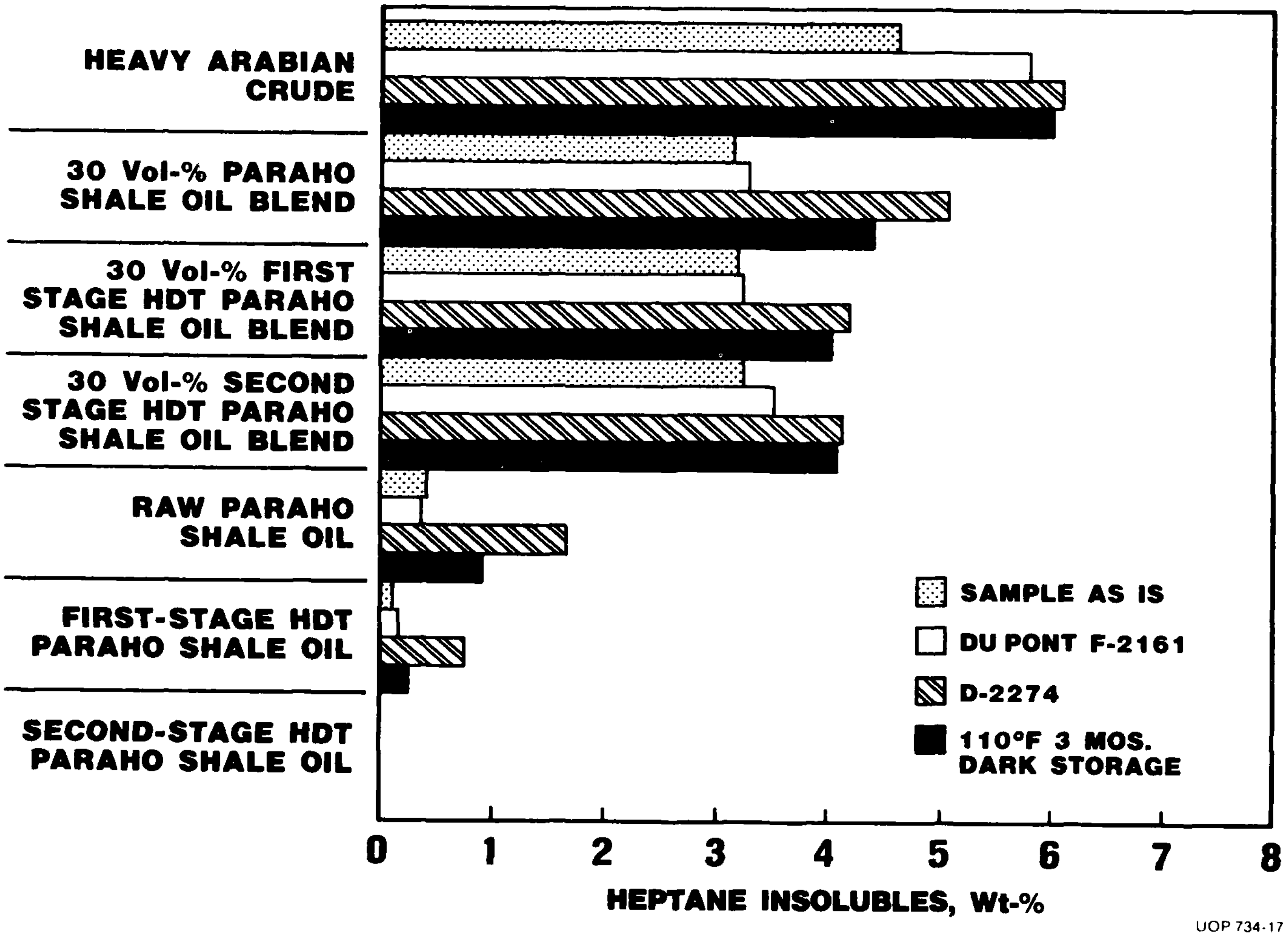

FIGURE 28

EFFECT OF STORAGE ON HEPTANE INSOLUBLES PARAHO SHALE OIL STUDY

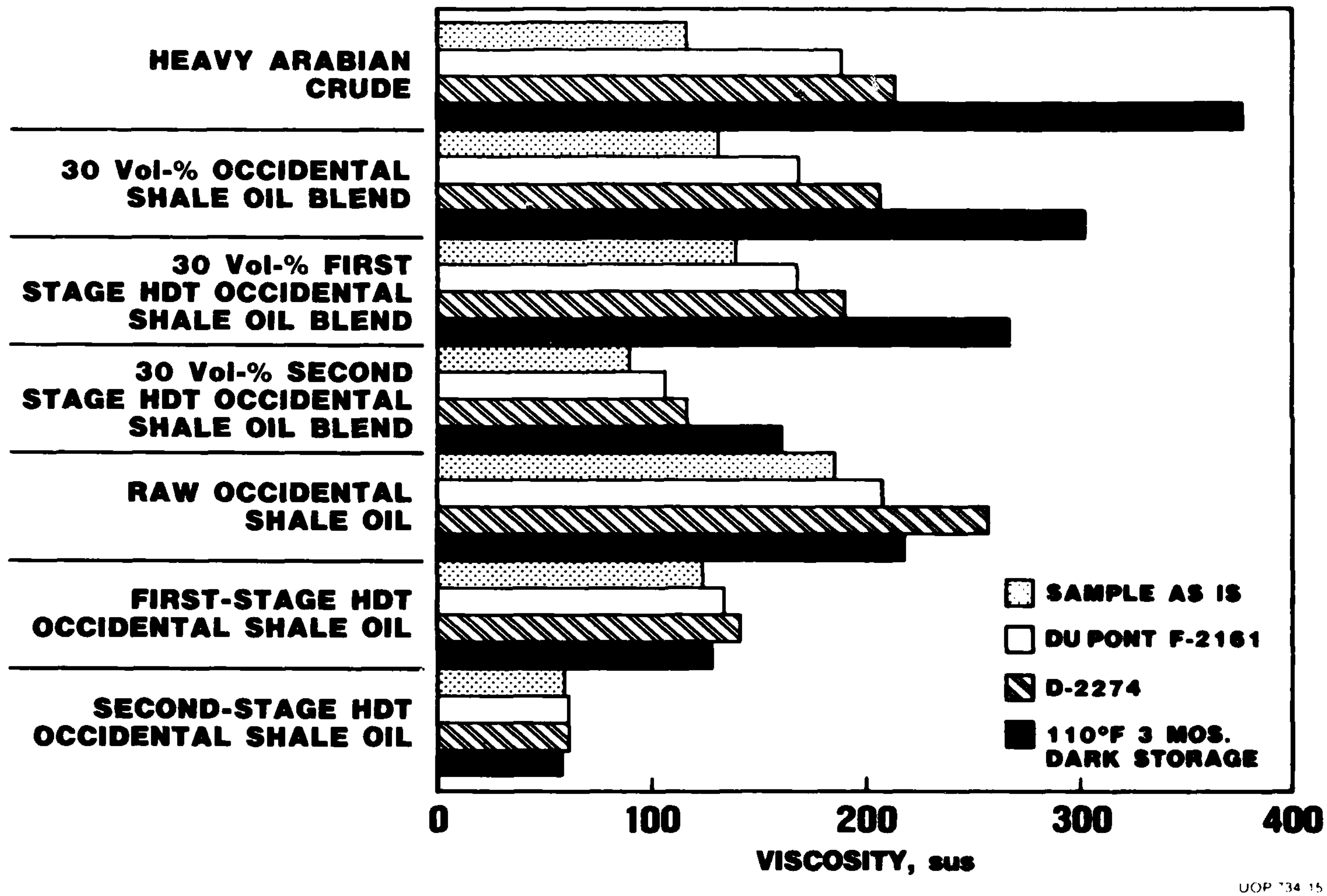

FIGURE 29

EFFECT OF STORAGE ON VISCOSITY OCCIDENTAL SHALE OIL STUDY

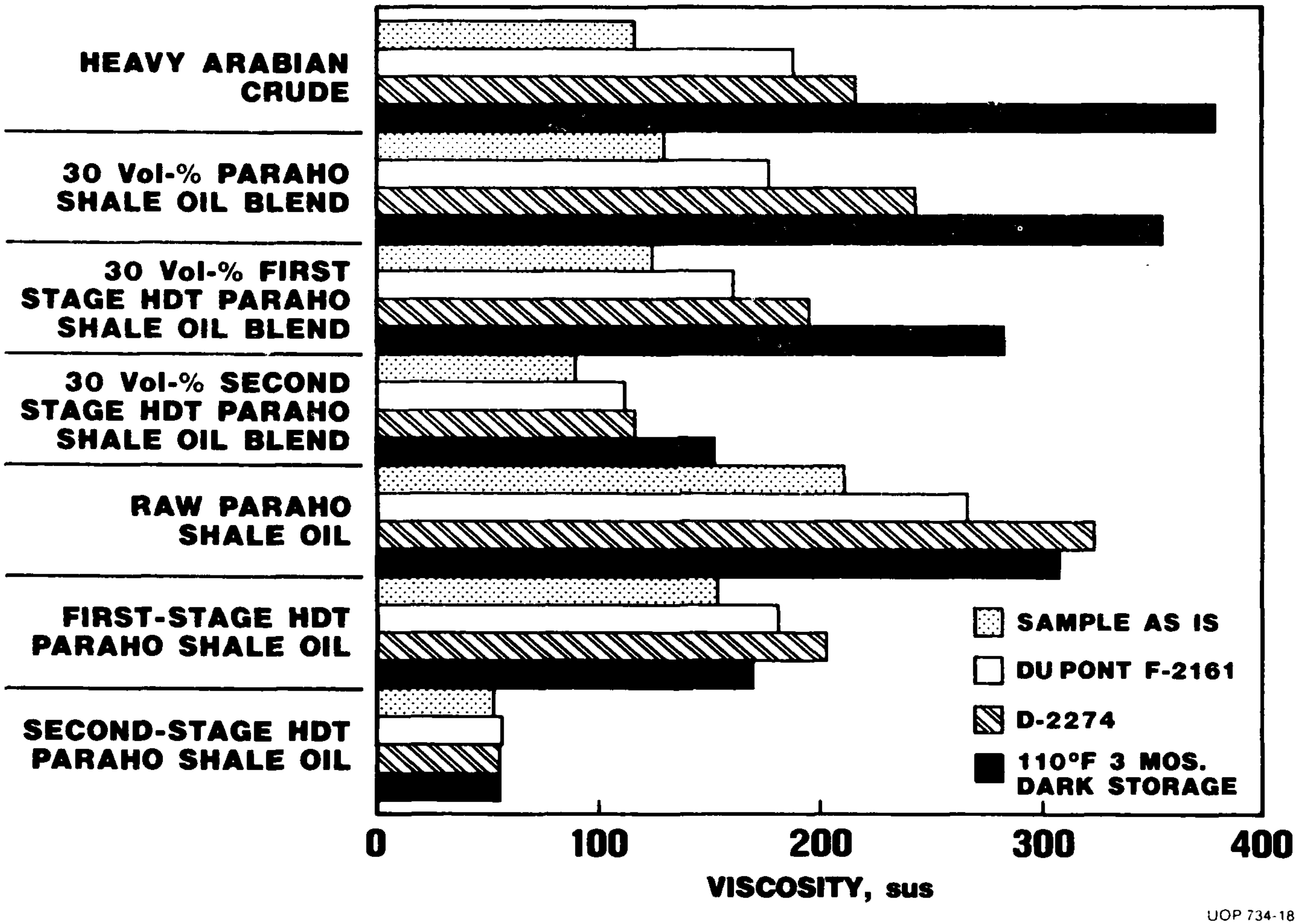

FIGURE 30

EFFECT OF STORAGE ON VISCOSITY
PARAHO SHALE OIL STUDY

SECTION VIII

SHALE OIL UPGRADING ECONOMICS

In addition to selecting a novel conversion processing scheme for high jet fuel yield, the proposed flow scheme will provide a realistic and economical solution to the problem of shale oil conversion. The UOP processing scheme, as shown in Figure 31, provides for the removal of arsenic and stabilization of the raw shale oil in a relatively moderate, first-stage pretreatment step. Denitrification is accomplished in a more severe, second-stage hydrotreatment. Finally, the upgraded shale oil is converted to transportation fuels in the hydrocracker. Hydrocracker jet and diesel fuel products do not require further treatment.

Study Basis

The basis for establishing the processing scheme and developing reliable estimates of external requirements and investment costs for the key processing units includes the following:

A. The refinery design and flow schemes are based on processing 100,000 barrels per stream day (BPSD) of desalted and deashed Occidental shale oil, described in Table 50.

B. Two primary products -- JP-4 and JP-8 aviation turbine fuels -- are required. Coproducts such as various grades of diesel fuel, fuel oil, motor gasoline, aviation gasoline, or other grades of turbine fuel may be produced.

C. Only commercially proven processes are to be considered in the refinery processing schemes.

D. There are no outside feed streams to be processed with the raw shale oil. Fuels for heating are to be internally generated.

E. The refinery is assumed to be a grassroots facility located at a Rocky Mountain site.

F. Capital Investment

1. Western U.S. location
2. 100,000 BPSD crude shale oil capacity
3. First quarter 1981 cost base
4. 100% equity financing
5. Investment timing over a three year construction period
   a. 25% first year
   b. 50% second year
   c. 25% third year
6. 10% invesment tax credit
7. 45% of plant onsites (not including feed and product storage) will be used to generate plant offsite cost.

G. Working Capital

1. 21 days crude storage capacity with 14 days crude inventory
2. 14 days product storage capacity with 7 day product inventory
3. Crude shale oil valued at $40.00 per barrel
4. Product valued at determined cost
5. Debt financed at 15%

H. Capital Return

1. 15% DCF rate of return on capital
2. 13 years sum of years digits depreciation
3. Zero salvage value

I. Operating Basis

1. 16 year plant operating life
2. 50% operating capacity first year, 100% thereafter
3. 90% on-stream factor

4. 100,000 BPSD capacity
5. All process fuel/heat requirements shall be generated internally from the original shale oil feed.

J. Operating Cost Basis

1. Crude Shale Oil -- $40.000 per barrel
2. Cooling Water -- $0.03 per 1000 gal
3. Electricity -- $0.045 per kWh
4. Operators -- $12.00 per hour
5. Helpers -- $10.50 per hour
6. Labor Supervision -- 25% of direct labor
7. Overhead -- 100% of direct labor
8. Federal and State Taxes -- 50%
9. Maintenance, Local Taxes and Insurance -- 4.5% of fixed investment
10. Product Values -- all liquid fuel products are of equal value
11. By-product Values
    a. Ammonia at $155/short ton
    b. Sulfur at $105/long ton

K. Miscellaneous

1. Use English units
2. Mass flow rates
    a. Barrels per stream day (BPSD)
    b. Short tons per day (ST/D)
    c. Standard cubic feet per day (SCFD)

Refinery Processing Scheme

The processing scheme for the production of JP-4 and JP-8 jet fuels, shown in Figures 32 and 33, respectively, are nearly identical except for the size of the units. Naphtha hydrotreating and Platforming units are added to the flow scheme when producing JP-8, and a partial oxidation unit is added to supplement the hydrogen plant when producing the JP-4 in the diesel fuel case. Various combinations of jet fuel and diesel fuel are produced by utilizing the same flow schemes and by varying the hydrocracking severity to produce the desired product slate. Overall material balances for all cases for JP-4 and JP-8 jet fuels are shown in Table 51.

First-Stage Hydrotreating (UOP RCD Unibon)

The desalted shale oil charge stock is combined with amine scrubbed recycle hydrogen gas plus make-up hydrogen gas (from the hydrogen plant), heated to the desired reaction temperature, by means of exchange and direct fired heaters, and charged to the reactors. The reactor effluent, after heat exchange with the incoming feed, is water washed, condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is amine treated and recycled to the reactor section. Ammonia-rich water is removed from the separator and sent to the sour water stripper. Liquid hydrocarbon product from the separator is not stripped or fractionated but pumped directly into the high-pressure, second-stage hydrotreater.

The first-stage hydrotreater saturates the olefins and diolefins by contacting the feedstock with high purity hydrogen over a catalyst bed. Iron and arsenic are removed along with most of the sulfur compounds. Essentially no arsenic and only small amounts of unsaturates remain; however, a high concentration of nitrogen compounds is still present in the first-stage product and must be removed in the more severe second-stage hydrotreating step.

Second-Stage Hydrotreating

The first-stage separator liquid is combined with the recycle hydrogen-rich gas plus make-up hydrogen (from the hydrogen plant), heated to the desired reactor temperature, by means of exchange and direct fired heaters, and charged to the reactors. The reactor effluent is heat exchanged with the reactor feed, water washed, condensed, cooled and sent to the product separator. The hydrogen-rich gas from the separator is recycled to the reactor, and the ammonia-rich water is drawn from the separator and treated in the sour water stripper. Liquid hydrocarbons from the separator are pressured directly to the hydrocracking unit (HC Unibon) for further processing.

The second-stage hydrotreating step completes the denitrification of the shale oil to less than 1000 wt-ppm. Hydrocarbon liquid to be used as an environmentally acceptable fuel oil for process heaters is drawn from the high-pressure hydrotreater separator. This material will be stripped, with the light ends going to fuel gas treating and the bottoms liquid used as fuel oil. The balance of the high pressure separator liquid will be used as hydrocracker feedstock. The two-stage hydrotreating yields are given in Table 52.

Hydrocracking (HC Unibon)

Hydrocracking is a highly versatile process for the conversion of a variety of petroleum/hydrocarbon fractions to yield more valuable, lower-boiling products. Along with the molecular weight reduction accomplished in the hydrocracking reactions, there is almost complete conversion of sulfur-, nitrogen- and oxygen-containing compounds, thus yielding products that are mixtures of essentially only paraffins, naphthenes and aromatics. The kerosine products yielded from the HC Unibon unit are of good quality. Both kerosine cuts (JP-4 and JP-8) are nearly sulfur free, low in aromatics, have low freeze points and good smoke points. These hydrocracked kerosines make good jet fuel blending stock.

The HC Unibon unit proposed for this refinery is a parallel-flow hydrocracker designed to process the hydrotreated Occidental shale oil into light ends, light and heavy naphthas and kerosine/diesel products. Several operational modes vary the end points on the kerosine to make the JP-4 or JP-8 jet fuels and the DF-2/DFM diesels. Tables 53 through 56 present the yield estimates and product properties when operating for JP-4 and JP-8 jet fuels including the alternative diesel cases.

The hydrotreated shale oil charge stock is combined with the recycle hydrogen-rich gas plus hydrogen make-up, heated to the desired reactor temperature by means of heat exchange and a direct fired heater, and charged to the reactor section. The reactor section effluent is water washed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is returned to the reactor section as recycle gas and hydrogen quench.

Ammonia is removed from the product separator with the wash water. The hydrocarbon liquid from the separator is flashed to the low pressure flash drum where much of the H_2S and light gases are removed to the fuel gas treating system. The low-pressure, flash hydrocarbon liquid is charged to a fired heater and sent to the product fractionator where the IBP-300°F material is taken overhead, the 300-520°F kerosine is stripped and blended with the C_5+ naphtha product from the overhead material into JP-4 jet fuel. For the JP-8 jet fuel case, a 300-550°F kerosine is stripped for flash point and sent to the product storage. When diesel products are required with the jet fuels, a lower side-cut draw is made on the product fractionator, and a side-cut stripper is provided to make flash point. The product fractionator bottoms material is combined with recycle hydrogen gas and make-up hydrogen and charged to the reactor section. Utilties consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

Light Ends Fractionation

The product fractionator overhead material is cooled, condensed and then collected in the overhead receiver. The overhead receiver gas is compressed and recontacted with the overhead naphtha liquid in the recontact drum. Net gas is removed to fuel gas treating, and the naphtha is sent to the naphtha splitter, where C_6 minus material is taken overhead and the C_7-300°F heavy naphtha is taken as bottoms product for blending into the JP-4 jet fuel, or used as feed to the naphtha hydrotreater and Platformer to make high octane gasoline when the plant is making JP-8 jet fuel. The naphtha splitter overhead (C_6-) material is charged to a debutanizer to remove C_4- material from the light naphtha (C_5/C_6). The debutanized light naphtha is blended with the heavy naphtha (C_7-300°F) and kerosine (300-520°F) to make JP-4, the wide-cut jet fuel or the light naphtha is blended into the gasoline pool with high-octane Platformate produced during the JP-8 jet fuel production. If required, part of the light naphtha can be utilized in the hydrogen plant as fuels/feedstock. A small depropanizer is used to separate the C_3 and lighter material from the butanes in the C_4- overhead liquid from the debutanizer. The depropanizer bottoms butanes are used to make vapor pressure in the gasoline during the JP-8 operation. Leftover light ends are sent to fuel gas treating prior to being used as hydrogen plant feedstock. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

Naphtha Hydrotreating (For JP-8 Cases Only)

The C_7-300°F hydrocracked naphtha from the bottoms of the naphtha splitter is charged to the naphtha hydrotreater, for complete desulfurization and other contaminant removal (oxygen and nitrogen), prior to reforming in a UOP Platforming unit. The naphtha is combined with hydrogen-rich recycle gas plus make-up hydrogen gas, heated to the desired reaction temperature by means of exchange and direct fired heater, and charged to the reactor. The effluent from the reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is recycled to the reactor section while net separator gas is sent to fuel gas.

The liquid product from the separator is sent to a stripper column for hydrogen sulfide and light ends removal. The C_6 plus stripper bottoms product is charged directly to the Platformer. Table 57 shows the naphtha hydrotreater yield estimate, while Tables 64 and 65 list the utilities. Table 66 presents the plant capacities and investment costs.

UOP Platforming (For JP-8 Cases Only)

In the UOP Platforming unit the hydrotreated naphtha is combined with the recycle hydrogen-rich gas stream, heated by means of exchange and a

The hydrotreated shale oil charge stock is combined with the recycle hydrogen-rich gas plus hydrogen make-up, heated to the desired reactor temperature by means of heat exchange and a direct fired heater, and charged to the reactor section. The reactor section effluent is water washed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is returned to the reactor section as recycle gas and hydrogen quench.

Ammonia is removed from the product separator with the wash water. The hydrocarbon liquid from the separator is flashed to the low pressure flash drum where much of the H_2S and light gases are removed to the fuel gas treating system. The low-pressure, flash hydrocarbon liquid is charged to a fired heater and sent to the product fractionator where the IBP-300°F material is taken overhead, the 300-520°F kerosine is stripped and blended with the C_5+ naphtha product from the overhead material into JP-4 jet fuel. For the JP-8 jet fuel case, a 300-550°F kerosine is stripped for flash point and sent to the product storage. When diesel products are required with the jet fuels, a lower side-cut draw is made on the product fractionator, and a side-cut stripper is provided to make flash point. The product fractionator bottoms material is combined with recycle hydrogen gas and make-up hydrogen and charged to the reactor section. Utilties consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

Light Ends Fractionation

The product fractionator overhead material is cooled, condensed and then collected in the overhead receiver. The overhead receiver gas is compressed and recontacted with the overhead naphtha liquid in the recontact drum. Net gas is removed to fuel gas treating, and the naphtha is sent to the naphtha splitter, where C_6 minus material is taken overhead and the C_7-300°F heavy naphtha is taken as bottoms product for blending into the JP-4 jet fuel, or used as feed to the naphtha hydrotreater and Platformer to make high octane gasoline when the plant is making JP-8 jet fuel. The naphtha splitter overhead (C_6-) material is charged to a debutanizer to remove C_4- material from the light naphtha (C_5/C_6). The debutanized light naphtha is blended with the heavy naphtha (C_7-300°F) and kerosine (300-520°F) to make JP-4, the wide-cut jet fuel or the light naphtha is blended into the gasoline pool with high-octane Platformate produced during the JP-8 jet fuel production. If required, part of the light naphtha can be utilized in the hydrogen plant as fuels/feedstock. A small depropanizer is used to separate the C_3 and lighter material from the butanes in the C_4- overhead liquid from the debutanizer. The depropanizer bottoms butanes are used to make vapor pressure in the gasoline during the JP-8 operation. Leftover light ends are sent to fuel gas treating prior to being used as hydrogen plant feedstock. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

Naphtha Hydrotreating (For JP-8 Cases Only)

The C_7-300°F hydrocracked naphtha from the bottoms of the naphtha splitter is charged to the naphtha hydrotreater, for complete desulfurization and other contaminant removal (oxygen and nitrogen), prior to reforming in a UOP Platforming unit. The naphtha is combined with hydrogen-rich recycle gas plus make-up hydrogen gas, heated to the desired reaction temperature by means of exchange and direct fired heater, and charged to the reactor. The effluent from the reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is recycled to the reactor section while net separator gas is sent to fuel gas.

The liquid product from the separator is sent to a stripper column for hydrogen sulfide and light ends removal. The C_6 plus stripper bottoms product is charged directly to the Platformer. Table 57 shows the naphtha hydrotreater yield estimate, while Tables 64 and 65 list the utilities. Table 66 presents the plant capacities and investment costs.

UOP Platforming (For JP-8 Cases Only)

In the UOP Platforming unit the hydrotreated naphtha is combined with the recycle hydrogen-rich gas stream, heated by means of exchange and a fired heater, then charged successively through the reforming reactors. Fired interheaters are provided between the reactors in order to achieve the desired reactor inlet temperatures.

The effluent from the last reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen-rich gas stream from the separator is recycled to the reactor section while the off-gas produced is used as make-up hydrogen for the naphtha hydrotreater and as feedstock to the hydrogen plant. The separator hydrocarbon liquid after recontacting with the compressed separator gas, is separated and charged to the stabilizer (debutanizer for motor fuel operation) where the light hydrocarbons are taken overhead to hydrocracker fractionation and the C_5+ Platformate is sent to gasoline blending.

The UOP Platformer is designed for processing C_7-300°F naphtha in a conventional fixed bed, semi-regenerative type reformer, featuring low pressure operation with gas recontacting giving maximum liquid recovery and high hydrogen purity. The yields and some of the major properties are noted in Table 58. The units are designed for 100 RON clear Platformate for the maximum JP-8 case, and 98 RON clear Platformate for the JP-8 plus diesel case. The Platformer is designed for conventional catalyst regeneration with an estimated first cycle length of twelve months.

The liquid C_4- material from the Platformer debutanizer is sent to the depropanizer in the fractionation section to recover butanes for gasoline blending. There is no attempt to recover propane, and all the light end hydrocarbons are taken to the fuel gas system for feed to the hydrogen plant. Part of the hydrogen produced from the Platformer net separator gas is used in the naphtha hydrotreater and the balance of the gas, the larger portion, feeds the hydrogen plant. Tables 64 and 65 present the utilities consumption, and Table 66 shows the capacities and investment requirements for the UOP Platforming unit.

Hydrogen Plant

A hydrogen plant is required to supply 97% hydrogen to operate the hydrogen consuming process units. Estimated hydrogen requirements and hydrogen plant sizes and yields are given in Table 59 for JP-4 cases and Table 60 for JP-8 cases.

The preferential feedstock to the hydrogen plant is treated fuel gas but where fuel gas is in short supply, light naphtha (C_5/C_6) is then used as a supplement. In the JP-4 plus diesel case, there is not enough fuel gas or light naphtha available, so a partial oxidation plant is used to obtain the balance of the hydrogen.

The basic steps for the steam-hydrocarbon reforming process in the production of hydrogen are desulfurization, two-stage CO conversion, CO_2 removal, methanation and compression to the required pressure levels.

A variety of feedstocks can be used, such as natural gas, methane, ethane, propane and butanes. Liquid feeds such as light naphthas are sometimes used. The feed should contain less than 0.5% olefins to prevent carbon formation. The hydrocarbons are charged to the charcoal absorber for sulfur removal then sent to the reformer furnace with steam. The gas is converted largely to hydrogen, CO and CO_2. The gases are cooled by the addition of steam or condensate and all are passed over catalyst in the CO converter. About 90 to 95% of the CO is converted to CO_2. The hot gases leaving the converter are cooled and then scrubbed with an amine solution to remove most of the CO_2. The gases are heated up after leaving the CO_2 absorber by exchange with gas coming from the CO converter and pass over catalyst in the methanator. Here all the carbon oxides are converted to methane by reaction with hydrogen. The product hydrogen gas from the methanator, saturated with water vapor, is cooled to 100°F.

Tables 62, 63, 64, 65 and 66 list the hydrogen plant utilities requirement, capacities and investment cost for each case.

Partial Oxidation (For JP-4 plus Diesel Case Only)

Even with lower hydrogen consumption in the JP-4 plus diesel case, the reduced supply of light feedstock (fuel gas and light naphtha) indicates that a partial oxidation unit is needed to supplement the hydrogen production from the steam reformer. The partial oxidation process is very flexible in regard to feedstocks. Residual oils from 1 to 10 °API gravity have routinely been processed. Raw shale oil could conceivably be used as feed but, because of the high arsenic content and other contaminants, the resulting hydrogen gas may be of poor quality. To avoid this problem, hydrotreated shale oil is used as the feedstock.

The treated shale oil is vaporized and mixed with oxygen and steam in the reactor. The first reaction phase is that of heating and cracking the hydrocarbon and dispersing it into oxygen (supplied by an air separation plant included in the scheme) and steam which acts as a moderator. In the second phase of reaction, the hydrocarbon burns when it reaches ignition temperature. The residence time is insufficient for complete combustion of the hydrocarbon, consequently one of the by-products is soot. A direct quench cools the gas and scrubs out the soot in a scrubber which is followed by the CO conversion step. The final composition of the product gas containing carbon dioxide and hydrogen is determined by the equilibrium condition of the shift reaction. The shift reaction is followed by carbon dioxide removal and a final methanation step to obtain the high purity hydrogen as a final product.

Estimated yields for the partial oxidation unit are shown in Table 61. Tables 63 and 66 show the partial oxidation unit utilities consumption, capacity and investment cost.

Amine Treating and Sulfur Recovery

Amine treating of refinery gases removes hydrogen sulfide and other acid gas constituents thus avoiding atmospheric pollution by SO_2 from combustion of these gases. The amine treating process is based on an absorption-regeneration cycle using aqueous solutions of an alkanolamine which reacts with acid gases. Hydrogen sulfide containing feed is contacted counter-currently with amine solution in an absorption or extraction column. Regenerated amine solution is fed into the top of the column and the rich solution taken from the bottoms through exchange to regeneration, where the acid gases are stripped with steam and recovered as hydrogen sulfide with the regenerated solution recycled back to the absorber. The hydrogen sulfide from the amine unit and sour water from the sour water stripper are charged to a Claus sulfur recovery unit for conversion to elemental sulfur.

The low-pressure hydrotreater (RCD Unibon) recycle gas and the net off-gases from the HC Unibon and naphtha hydrotreater are amine treated for hydrogen sulfide removal. The off-gases are treated prior to being used as feedstock in the hydrogen plant or fuel gas to the heaters. In these processing schemes most of the treated light gases are used as hydrogen plant feedstock with little left over for heating.

Sour Water Treating

In the hydrocracking and hydrotreating processing units, water is injected to prevent build-up of salts on the surface of heat exchange tubes. Wash water used to dissolve ammonia and some hydrogen sulfide cannot be disposed of in the conventional refinery sewer system because of its chemical content. This sour water is charged to a stripper where hydrogen sulfide and ammonia are steam stripped from the water. The stripped water is returned to the refinery and the released gases, hydrogen sulfide and ammonia, are separated with the hydrogen sulfide processed in the sulfur plant for elemental sulfur and the ammonia recovered in a liquefaction plant.

Recovered Products

Aviation Turbine Fuels

The refinery is designed to produce two types of aviation turbine fuels as the major products. These are:

A. JP-4 Jet Fuel -- This military jet fuel is wide-cut with a distillation range from C_5-518°F and with gravity limitations between 45-57 °API. Table 67 compares the product qualities of the various cases with the Military Specifications for JP-4. The maximum JP-4 case product meets these specifications, but the JP-4 in the JP-4 plus diesel case has a slightly higher distillation than allowed in the specification. The compositions of the JP-4 jet fuels are:

Component	Max. JP-4 Case			JP-4 + Diesel Case		
	BPSD	ST/D	°API	BPSD	ST/D	°API
Lt. Naph. (C_5/C_6)	11,819	1,375.1	81.4	5,601	649.7	82.1
C_7-300°F Naph.	7,100	947.3	54.2	3,047	406.6	54.2
300-520°F Kero.	72,841	10,230.7	44.9	45,307	6,363.5	44.9
TOTAL	91,760	12,553.1	49.6	53,955	7,419.8	48.7

B. JP-8 Jet Fuel -- This military jet fuel is of the kerosine type, similar to ASTM Jet A-1 fuel, with a maximum distillation end point of 572°F, and with gravity limitations between 37-51 °API. Table 67 shows a comparison between the estimated product for each case with the JP-8 Military Specification. The jet fuel product does meet, or exceed, these specifications. The quantity and quality of the JP-8 jet fuels are:

Component	Max. JP-8 Case			JP-8 + Diesel Case		
	BPSD	ST/D	°API	BPSD	ST/D	°API
300-550°F Kero.	80,742	11,380.1	44.3	55,219	7,782.8	44.3

Diesel Fuels

In the alternative cases for JP-4 and JP-8, diesel fuels are produced along with the respective jet fuels. The diesel fuels recovered from these cases satisfy both the DF-2 Diesel and Marine Diesel Specifications. As noted in Table 68, the JP-4 + DF-2/DFM and JP-8 + DF-2/DFM diesels are very similar except for slight differences in properties. The quantity and composition of the diesel fuels are:

Component	JP-4 + DF-2/DFM Case			JP-8 + DF-2/DFM Case		
	BPSD	ST/D	°API	BPSD	ST/D	°API
520-700°F Diesel	36,871	5,376.9	38.4	-	-	-
550-700°F Diesel	-	-	-	29,883	4,373.0	37.8

Motor Gasoline Fuels

Motor gasolines are produced only when JP-8 jet fuels are made. The motor gasoline blended in this study is special grade unleaded, which meets Military Specification and Federal Specification VV-G-1690B dated July 1, 1978. Table 69 compares the study blends with the required specification and the blends equal, or exceed, these specifications. The composition of the gasoline blends is as follows:

Max. JP-8 Case Gasoline Blend

Component	BPSD	ST/D	Sp. Gr.	RVP	RON Clear	MON Clear	R+M/2 Clear
Platformate	5,139	740.8	0.8233	4.0	100.0	88.6	
Lt. Naphtha	2,776	322.8	0.6643	11.0	75.0	73.0	
Mixed Butanes	934	93.9	0.5743	-	98.5	94.3	
TOTAL	8,849	1,157.5	0.7471	13.5	92.0	84.3	88.1

JP-8 + DF-2/DFM Case Gasoline Blend

Component	BPSD	ST/D	Sp. Gr.	RVP	RON Clear	MON Clear	R+M/2 Clear
Platformate	2,337	333.8	0.8159	3.9	98.0	87.0	
Hvy. Naphtha	280	37.3	0.7620	0.3	59.0	57.0	
Lt. Naphtha	454	52.7	0.6625	11.0	75.0	73.0	
Mixed Butanes	450	45.3	0.5743	-	98.5	94.3	
TOTAL	3,521	469.1	0.7609	13.5	92.0	83.7	87.9

It should be noted that both grades of gasoline meet or exceed the octane requirments and the other properties required by the gasoline specs. The composition of these blends is toward a light gasoline with a large percentage of gasoline composed of light naphtha and butanes, but the blends are acceptable by the specifications.

Refinery Fuel Gas

As the material balances shown in Table 51 indicate, no fuel gas is used for heating in any of the processing schemes. All the fuel gas is treated and sent to the hydrogen plant as feedstock.

Refinery Fuel Oil

All heating will be done with fuel oil or naphtha that is not processed into gasoline. Fuel oil is drawn from the refinery processing scheme after the second-stage hydrotreater. The high-pressure separator liquid, drawn for fuel oil, is stabilized in the fuel oil stabilizer with the light hydrocarbon material going to fuel gas treating and the stabilized liquid used as fuel oil. The light naphtha used as fuel in the Max. JP-8 case can be burned in the hydrogen plant. Table 51, Overall Material Balance, indicates the quantities of fuel oil used in each case.

Recovered By-Products

Sulfur -- Approximately 97.5 short tons per stream day of sulfur are recovered from the sulfur plant in each of the processing cases.

Ammonia -- Between 306-307 short tons per stream day of liquid ammonia are recovered from the ammonia liquefaction plant in each of the processing cases.

Operating Cost

The overall refinery operating costs for the JP-4 and JP-8 cases are shown in Tables 70 through 7[illegible] Operating costs are divided into direct and indirect operating costs which are as follows:

Direct Operating Cost

Refinery Labor -- Refinery labor includes all the personnel for the process units hired at $12.00 per hour for operators and $10.50 per hour for helpers. To arrive at a total labor cost, a 100% overhead allowance is added to these base rates. A 25% allowance for supervision is also made.

Maintenance Allowance -- The maintenance allowance covers normal operating maintenance and turnaround contract maintenance for all refinery equipment including process units, offsites and depreciable assets. An amount equal to 3% of erected plant investment is allocated for maintenance.

Utilities -- Refinery fuel is generated internally for both JP-4 and JP-8 cases. Power is purchased at $0.045 per kWh, and cooling water is priced at $0.03 per 1000 gallons. Boiler feed water is estimated at $0.50 per 1000 pounds. Steam (600 psig) is generated at $0.68 per 1000 pounds (fuel provided from internal sources). Cold treated water is purchased at $0.07 per 1000 pounds. All utilities are consumed at normal average operating rates.

Catalyst, Solvents and Chemicals -- Catalyst consumption is based on the expected catalyst life for normal operating conditions. Similarly, solvents and chemicals are based on normal average operating usage.

Indirect Operating Cost

Local Taxes -- An allowance of 1% of erected plant investment, catalyst and working capital is allocated toward local taxes.

Insurance -- An allowance of 1/2% of erected plant investment, catalyst and working capital is allocated toward insurance.

Process Design, Capital Cost and Utilities

Process designs were prepared for the first- and second-stage hydrotreaters and for the primary conversion section, the hydrocracker. These designs were based on the yields and operating conditions developed from the specific laboratory and pilot plant data generated during the earlier phases of this project. Each process design includes a heat and material balance, characteristics of principal equipment, and a detailed process flow diagram. The heat and material balance includes stream quantities (mass and volume) and compositions (H_2, H_2S, NH_3, H_2O, light hydrocarbons), molecular weights, flowing densities and enthalpies entering and leaving each major equipment item, in addition to pressures and temperatures.

In order to provide more definitive cost data for these primary units, the process design was used as a basis for generating EFCEST (Engineering for Cost Estimating) data. EFCEST data provide a sufficient level of detailed project engineering work to appropriately describe the equipment required. The EFCEST data were then used to prepare a detailed cost estimate with an estimated precision of ±25% for first quarter, 1981 U.S. Gulf Coast construction. To obtain a Western location construction cost, the Gulf Coast cost for plant and offsites were increased by 5%.

Material balances prepared for the naphtha hydrotreating and Platforming units, amine treating and sulfur recovery, sour water stripping, raw feed desalting, ammonia plant and hydrogen production units include stream quantities and compositions. Considering the extent of UOP experience with these types of units, reliable cost and utility estimates were provided without preparing EFCEST data and detailed cost estimates. The material and labor estimates provided for the above units were derived by scaling detailed estimates prepared for similar units.

In Table 66, the capacity and the estimated erected cost (EEC) for individual process units are shown. The costs for the JP-4 and JP-8 cases are similar with the exception that a naphtha hydrotreater and Platformer unit combination is included in the JP-8 case, and a partial oxidation unit is added to the JP-4 plus diesel case. The common facilities cost includes such items as buildings (process control house and substations), electrical power distribution, area lighting and site development in the process area.

Offsite costs are influenced more by the characteristics of the site, local regulations and policies of the refinery than by minor differences in process scheme. Allowances for offsite costs are included, with recognition of special requirements such as for waste treatment, where applicable. The offsite facility cost estimates were based on 45% of the plant onsite investment plus the cost of specified tankage capacity for storing crude and products. This basis was used to estimate offsite facility costs as no other design information was available. As such, the offsite cost is an order-of-magnitude cost estimate and has no meaningful accuracy range.

The capital investment summary for the JP-4 and JP-8 cases is presented in Table 74. The total capital investment is estimated to be $\$902 \times 10^6$ for the maximum JP-4 case and $\$939 \times 10^6$ for the maximum JP-8 case. For the alternative diesel cases, the JP-4 + DF-2/DFM case has a investment of $\$989 \times 10^6$ and the JP-8 + DF-2/DFM case a $\$905 \times 10^6$ investment.

Utility requirements are estimated from the process design data and the information provided for the auxiliary units. Utilities estimated include: electric power, fuel, steam at recommended pressure levels, boiler feedwater, condensate, cold process water and cooling water.

Linear Programming

The use of UOP's linear programming (LP) capabilities permitted the evaluation of numerous processing and product blending alternatives required in this shale oil upgrading study. The linear programming technique, using a multitude of mathematical calculations, allowed various alternatives to be quickly examined to determine the best or optimal processing scheme. Once developed, LP models can be used to perform sensitivity analysis, wherein the effect of varying feedstock value, product prices, quantities and specification can be considered.

The UOP LP system was developed over the years to apply this powerful mathematical method to the analysis of a grassroots refinery and expansion projects. LP techniques are effectively used in: feedstock evaluation and selections, operations planning, financial planning for new facilities or expansion of existing ones, and development of planned turnaround maintenance. Combining the market data of product prices and demands with data describing technology and economic factors, the LP model can be used to evaluate many alternatives quickly and efficiently. Although the results are a linear representation of reality, they can give the planner a logical basis for a systematic approach to solving these problems.

To illustrate the mathematical relationships and the extent to which the refinery interactions are considered, a matrix representation of the linear equations is used to describe the refinery. In this arrangement, data relationships cascade from one activity to the next, much the same way material flows through the refinery. The model can consider the following general components of refinery profitability:

- Availability of raw materials
- Component blending relationships and recycle streams
- Process unit material balances
- Addition requirements for product quality improvements
- Utility consumptions and conversions (purchase vs. internal generation)
- Market demands for finished products.

The constraints or limitations on the model are contained in the rows of the matrix. The constraints considered in the refinery optimization are:

- Raw material purchase limits
- Unpooled utility limits to sale or purchase
- Product quality specifications
- Material balances on all streams in the refinery
- Capacity limits in process units
- Additive blending
- Utility balances (choice between purchase and internal generation)
- Product demands at market centers
- Physical and social requirements (e.g., emission limits)

Investment in onsite process equipment and related offsite facilities is handled in a manner that considers the non-linear relationship between capital cost and plant capacity. UOP's linear programming system has the ability to recurse on the capital cost to ensure that the capital charges used by the model are consistent with the calculated process unit capacity. The effect of physical and social policy requirements can be evaluated by placing additional constraints on the model and evaluating the results.

The output of the LP program is in the form of reports that allow management to evaluate the results in familar terms including such terms as:

- Material balances including plant yields and product blends
- Processing schemes
- Utility balances
- Investment requirements
- Operating requirements
- Production costs

In addition, the LP allows the investigation of the sensitivity of the solution through a technique called post optimal analysis. This feature permits the quantified measurement of varying key parameters such as:

- Sales of selected products on various markets
- Capacity of particular process units
- Finished product qualities
- Prices of products and feedstocks

Conclusions

The total production costs for the JP-4 and JP-8 cases are tabulated in Table 75. Incorporating the feedstock cost, operating costs, capital charges, taxes and a 15% DCF rate, and assuming that all liquid products have equal value, the cost of total liquid fuel production in terms of $/Bbl of shale oil feed are as follows:

Case	$/Bbl of Feed
Max. JP-4	52.14
JP-4 + DF-2/DFM	53.42
Max. JP-8	52.68
JP-8 + DF-2/DFM	52.15

The difference in cost for the various cases is almost entirely due to the variations in capital cost, especially in the JP-4 + DF-2/DFM case which has the partial oxidation unit.

The product costs can be stated on a "per barrel of total liquid feed" basis and this is calculated by dividing production costs by the volume fraction yield of liquid fuel. Tabulated below are the results of the calculation for each case:

Case	Total Liquid Product, BPSD	$/Bbl of Liquid Products
Max. JP-4	91,760	56.82
JP-4 + DF-2/DFM	90,826	58.82
Max. JP-8	89,591	58.80
JP-8 + DF-2/DFM	88,623	58.85

A more detailed analysis of these four cases is provided in the pro forma financial statements attached as Appendices B.1 to B.4 and in the Standard Optimization Reports attached as Appendices B.5 to B.8.

TABLE 50. SHALE OIL INSPECTION

Occidental Shale Oil

Feed Source	Desalted Shale Oil
Gravity, °API	22.9
Distillation (D-1160), °F	
IBP	376
50%	712
EP	953
% Over	87
Sulfur, wt-%	0.64
Nitrogen, wt-%	1.51
Pour Point, °F	+65
BS and W, vol-%	0.2
Conradson Carbon, wt-%	1.36
Carbon, wt-%	79.3
Hydrogen, wt-%	12.2
Oxygen, wt-%	0.65
Metals, wt-ppm	
Arsenic	27.5
Iron	23.0
Nickel	10.0
Vanadium	5.0
Ash, wt-%	0.014
Bromine Number	23.5

TABLE 51. OVERALL MATERIAL BALANCES

JP-4 and JP-8 Jet Fuel Cases

	Max. JP-4			JP-4 + DF-2/DFM			Max. JP-8			JP-8 + DF-2/DFM		
Feed	Wt-%	Vol-%	BPSD	Wt-%	Vol-%	BPSD	Wt-%	Vol-%	BPSD	Wt-%	Vol-%	BPSD
Shale Oil	100.00	100.00	100,000	100.00	100.00	100,000	100.00	100.00	100,000	100.00	100.00	100,000
Liquid Products												
Gasoline	-	-	-	-	-	-	7.21	8.85	8,849	2.92	3.52	3,521
Jet Fuel JP-4	78.23	91.76	91,760	46.24	53.96	53,955	-	-	-	-	-	-
Jet Fuel JP-8	-	-	-	-	-	-	70.92	80.74	80,742	48.50	55.22	55,219
Diesel (DF-2/DFM)	-	-	-	33.51	36.87	36,871	-	-	-	27.25	29.88	29,883
Total Liquid Products	78.23	91.76	91,760	79.75	90.83	90,826	78.13	89.59	89,591	78.67	88.62	88,623
By-Products												
Sulfur	0.61	-	-	0.61	-	-	0.61	-	-	0.61	-	-
Ammonia	1.91	-	-	1.91	-	-	1.92	-	-	1.91	-	-
Water (Net Make)	0.73	0.66	664	0.73	0.66	664	0.73	0.66	664	0.73	0.66	664
Total By-Products	3.25	-	-	3.25	-	-	3.26	-	-	3.25	-	-
Streams Utilized as Fuel												
Fuel Oil	13.78	14.62	14,622	9.88	10.48	10,481	8.43	8.95	8,947	13.50	14.32	14,319
Naphtha	-	-	-	-	-	-	5.57	7.69	7,687	-	-	-
Total Fuels	13.78	14.62	14,622	9.88	10.48	10,481	14.00	16.64	16,634	13.50	14.32	14,319
Material Lost in Production												
Total Losses	4.74	-	-	7.12	-	-	4.61	-	-	4.58	-	-

TABLE 52. OVERALL REACTOR YIELDS

Low- and High-Pressure Hydrotreating

	JP-4 and JP-8 Cases	
Feed	Wt-%	(SCFB) LV-%
Shale Oil	100.00	100.00
Hydrogen (Chemical)	2.36	(1425)
Total	102.36	
Products		
Water	0.73	
Ammonia	1.85	
Hydrogen Sulfide	0.68	
Propane and Lighter	0.76	
Butanes	0.32	0.51
Pentanes	0.53	0.78
Hexane +	97.49	103.13
Total	102.36	104.42
Estimated Properties of C_6+		
API Gravity	31.8	
Sulfur, wt-%	0.003	
Nitrogen, wt-%	0.09	
C_7 Insolubles, wt-%	<0.05	
Bromine Number	1.1	
Distillation (D-1160), °F		
IBP	245	
50%	646	
EP	1034	

TABLE 53. REACTOR YIELDS

HC Unibon

Feed	Maximum JP-4 Wt-%	Maximum JP-4 (SCFB) LV-%
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	1.57	(885)
Total	101.57	
Products		
Ammonia	0.11	
Propane and Lighter	3.53	
Butanes	4.85	
Light Naphtha (C_5/C_6)	11.25	14.49
Heavy Naphtha (C_7-300°F)	6.98	7.83
Kerosine (300-520°F)	74.85	79.84
Total	101.57	102.16

Estimated Properties

	Charge	C_5/C_6	Naphtha	Kerosine
Dist. Range, °F			C_7-300	300-520
API Gravity	31.8	81.6	54.3	45.0
Sulfur, wt-ppm	30	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3
Distillation (D-1160), °F				
IBP	245	90	200	300
50%	646	130	240	404
EP	1034	180	285	520
RVP, psi	-	12.9	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-
RON Clear	-	75	59	-
RON + 3 cc TEL/gal	-	93	78	-
Flash Point, °F	-	-	-	100
Aromatics, vol-%	-	-	-	9.0
Freeze Point, °F	-	-	-	-58
Naphthalenes, wt-%	-	-	-	0.4
Smoke Point, mm	-	-	-	27

* Total hydrotreater, high-pressure separator liquid.

TABLE 54. REACTOR YIELDS

HC Unibon

Feed	JP-4 + DF-2/DFM Wt-%	(SCFB) LV-%
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	1.43	(803)
Total	101.43	
Products		
Ammonia	0.11	
Propane and Lighter	2.02	
Butanes	2.38	
Light Naphtha (C_5/C_6)	5.21	6.76
Heavy Naphtha (C_7-300°F)	3.09	3.47
Kerosine (300-520°F)	48.03	51.24
Diesel (520-700°F)	40.59	41.67
Total	101.43	103.14

Estimated Properties

	Charge	C_5/C_6	Naphtha	Kerosine	Diesel
Dist. Range, °F			C_7-300	300-520	520-700
API Gravity	31.8	82.3	54.3	45.0	38.4
Sulfur, wt-ppm	30	3	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3	3
Distillation (D-1160), °F					
IBP	245	90	200	300	520
50%	646	130	240	404	605
EP	1034	180	285	520	700
RVP, psi	-	12.9	-	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-	-
RON Clear	-	75	59	-	-
RON + 3 cc TEL/gal	-	93	78	-	-
Flash Point, °F	-	-	-	100	268
Aromatics, vol-%	-	-	-	9.0	-
Freeze Point, °F	-	-	-	-50	-
Naphthalenes, wt-%	-	-	-	0.4	-
Smoke Point, mm	-	-	-	27	-
Pour Point, °F	-	-	-	-	0
Cetane Number	-	-	-	-	56
Cloud Point, °F	-	-	-	-	5
Aniline Point, °F	-	-	-	-	198
Viscosity, cSt at 100°F	-	-	-	-	4.4

* Total hydrotreater, high-pressure separator liquid.

TABLE 55. REACTOR YIELDS

HC Unibon

Feed	Maximum JP-8 Wt-%	(SCFB) LV-%
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	1.55	(874)
Total	101.55	
Products		
Ammonia	0.11	
Propane and Lighter	3.13	
Butanes	4.25	
Light Naphtha (C_5/C_6)	9.78	12.60
Heavy Naphtha (C_7-300°F)	5.99	6.73
Kerosine (300-550°F)	78.29	83.18
Total	101.55	102.51

Estimated Properties

	Charge	C_5/C_6	Naphtha	Kerosine
Dist. Range, °F			C_7-300	300-550
API Gravity	31.8	81.7	54.3	44.3
Sulfur, wt-ppm	30	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3
Distillation (D-1160), °F				
IBP	245	90	200	300
50%	646	130	240	419
EP	1034	180	285	550
RVP, psi	-	12.9	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-
RON Clear	-	75	59	-
RON + 3 cc TEL/gal	-	93	78	-
Flash Point, °F	-	-	-	100
Aromatics, vol-%	-	-	-	10
Freeze Point, °F	-	-	-	-58
Naphthalenes, wt-%	-	-	-	1.5
Smoke Point, mm	-	-	-	26

* Total hydrotreater, high-pressure separator liquid.

TABLE 56. REACTOR YIELDS

HC Unibon

Feed	JP-8 + DF-2/DFM Wt-%	(SCFB) LV-%
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	1.43	(803)
Total	101.43	
Products		
Ammonia	0.11	
Propane and Lighter	2.02	
Butanes	2.38	
Light Naphtha (C_5/C_6)	5.21	6.76
Heavy Naphtha (C_7-300°F)	3.09	3.47
Kerosine (300-550°F)	56.74	60.29
Diesel (550-700°F)	31.88	32.62
Total	101.43	103.14

Estimated Properties

	Charge	C_5/C_6	Naphtha	Kerosine	Diesel
Dist. Range, °F			C_7-300	300-550	550-700
API Gravity	31.8	82.3	54.3	44.3	37.8
Sulfur, wt-ppm	30	3	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3	3
Distillation (D-1160), °F					
IBP	245	90	200	300	550
50%	646	130	240	419	620
EP	1034	180	285	550	700
RVP, psi	-	12.9	-	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-	-
RON Clear	-	75	59	-	-
RON + 3 cc TEL/gal	-	93	78	-	-
Flash Point, °F	-	-	-	100	288
Aromatics, vol-%	-	-	-	10	-
Freeze Point, °F	-	-	-	-58	-
Naphthalenes, wt-%	-	-	-	1.5	-
Smoke Point, mm	-	-	-	26	-
Pour Point, °F	-	-	-	-	0
Cetane Number	-	-	-	-	56
Cloud Point, °F	-	-	-	-	5
Aniline Point, °F	-	-	-	-	200
Viscosity, cSt at 100°F	-	-	-	-	4.5

* Total hydrotreater, high-pressure separator liquid.

TABLE 57. REACTOR YIELDS

Naphtha Hydrotreating Unit

	Max. JP-8 and JP-8 + DF-2/DFM	
Feed	Wt-%	(SCFB) LV-%
Hydrocracked Naphtha (C_7-300°F)	100.00	100.00
Hydrogen (Chemical)	0.03	(16)
Total	100.03	
Products		
Hydrogen Sulfide	0.02	
Propane and Lighter	0.02	
Butanes	0.01	
Pentanes	0.02	
Hexane +	99.96	100.01
Total	100.03	100.01
Properties of Hexane +		
API Gravity	54.4	
Sulfur, wt-%	0.00005	
Hydrocarbon Type, vol-%		
P	44	
N	49	
A	7	

TABLE 58. REACTOR YIELDS

UOP Platforming Unit

	Maximum JP-8		JP-8 + DF-2/DFM	
Feed	Wt-%	(SCFB) LV-%	Wt-%	(SCFB) LV-%
Hydrotreated Naphtha (C_7-300°F)	100.00	100.00	100.00	100.00
Products				
Hydrogen	2.65	(1332)	2.54	(1276)
Propane and Lighter	7.00		6.26	
Butanes	3.95	5.23	3.53	4.67
C_5+ Platformate	86.40	79.97	87.67	81.85
Total	100.00		100.00	
Properties of C_5+ Platformate				
API Gravity	40.4		41.9	
RON Clear	100.0		98.0	
RON + 3 cc TEL/USG	105.2		103.7	
MON Clear	88.6		87.0	
MON + 3 cc TEL/USG	92.7		91.5	
RVP, psi	4.0		3.9	

TABLE 59. ESTIMATED YIELDS

Hydrogen Plant -- Steam Reforming

Feed to H_2 Plant	JP-4 Case BPSD	Sp.Gr.	MW	MMSCFD	Wt-%	JP-4 + DF-2/DFM Case BPSD	Sp.Gr.	MW	MMSCFD	Wt-%
Treated Fuel Gas			24.3	45.6	95.1			18.2	35.1	100.0
Light Naphtha	652	0.6645	-	-	4.9	-	-	-	-	-
Total Feed					100.0					100.0
Products										
Hydrogen				247.5	42.7				141.4	44.5
CH_4				7.6	10.5				4.4	11.0
Total H_2 (97% Purity)				255.1	53.2				145.8	55.5
Process Loss					46.8					44.5
Total Products					100.0					100.0

Estimated Process Units H_2 Requirements

Unit	JP-4 Case H_2 MMSCFD	JP-4 + DF-2/DFM Case H_2 MMSCFD
Low- and High-Pressure Hydrotreater	154.3	154.3
Hydrocracker (HC Unibon)	93.2	82.9
Total Hydrogen Required	247.5	237.2
Hydrogen Required from Partial Oxidation	0	95.8

TABLE 60. ESTIMATED YIELDS

Hydrogen Plant -- Steam Reforming

Feed to H_2 Plant	JP-8 Case					JP-8 + DF-2/DFM Case				
	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%
Treated Fuel Gas			22.3	43.7	83.9			17.8	35.4	55.8
Platformer Gas			8.7	10.8	8.1			6.7	4.3	2.6
Light Naphtha	1060	0.6643	-	-	8.0	5345	0.6625	-	-	41.6
Total Feed					100.0					100.0
Products										
Hydrogen				252.5	43.7				240.3	42.9
CH_4				7.8	10.8				7.4	10.5
Total H_2 (97% Purity)				260.3	54.5				247.7	53.4
Process Loss					45.5					46.6
Total Products					100.0					100.0

Estimated Process Units H_2 Requirements

Unit	JP-8 Case H_2 MMSCFD	JP-8 + DF-2/DFM Case H_2 MMSCFD
Low- and High-Pressure Hydrotreater	154.3	154.3
Hydrocracker (HC Unibon)	98.0	85.8
Naphtha Hydrotreater	0.2	0.2
Total Hydrogen Required	252.5	240.3

TABLE 61. ESTIMATED YIELDS

Hydrogen Plant -- Partial Oxidation

	JP-4 + DF-2/DFM Case			
Feed to H_2 Plant	BPSD	Sp.Gr.	MMSCFD	Wt-%
HT Shale Oil	6906	0.8640		100.0
Products				
Hydrogen			95.8	24.4
CH_4			3.0	6.0
Total H_2 (97% Purity)			98.8	30.4
Process Loss				69.6
Total Products				100.0

TABLE 62. UTILITY CONSUMPTION

Maximum JP-4

	Power, kWh	Steam, M lb/hr HP	Steam, M lb/hr MP	Steam, M lb/hr LP	BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	27,797	-29.5	-	+12.1	-14.4	2597	677	35.8
Hydrogen Plant (Steam Reforming)	8,045	+177.4	-	-	-576.4	472	1963	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2455	-	-
Sulfur Plant	100	-1.0	+34.5	+44.9	-83.0	-	-	-
Sour Water Treating	351	-	-213.7	-	+213.7	4141	-	-
Fractionation	566	-	-	-38.2	+38.2	733	74	-
Fuel Oil Stabilizer	105	-	-	-	-	214	31	-
TOTAL	50,980	-1.0	-186.7	-23.6	-224.1	10,724	3043	210.4

NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 63. UTILITY CONSUMPTION

JP-4 + DF-2/DFM

	Power, kWh	Steam, M lb/hr HP	Steam, M lb/hr MP	Steam, M lb/hr LP	BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	23,171	-	+70.4	+44.3	-148.2	1661	653	34.7
Hydrogen Plant (Steam Reforming)	4,661	+97.5	-	-	-322.9	282	1110	-
Hydrogen Plant (Partial Oxidation)	27,384	+186.1	-	-	-166.2	21,657	187	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-83.0	-	-	-
Sour Water Treating	349	-	-212.4	-	+212.4	4126	-	-
Fractionation	262	-	-	-17.9	+17.9	339	34	-
Fuel Oil Stabilizer	125	-	-	-	-	254	37	-
TOTAL	70,068	+134.7	-115.0	+28.8	-292.2	30,885	2319	209.3

NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 64. UTILITY CONSUMPTION

Maximum JP-8

	Power, kWh	Steam, M lb/hr HP	Steam, M lb/hr MP	Steam, M lb/hr LP	BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	29,559	-31.3	-	+12.9	-15.3	2761	720	38.1
Naphtha Hydrotreating	191	-	-	-	-	53	5	-
Platforming	659	+16.3	-0.2	-	-17.4	382	87	-
Hydrogen Plant (Steam Reforming)	8,142	+185.1	-	-	-595.1	468	2016	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-83.0	-	-	-
Sour Water Treating	358	-	-218.5	-	+218.5	4188	-	-
Fractionation	531	-	-	-37.0	+37.0	760	68	-
Fuel Oil Stabilizer	64	-	-	-	-	131	19	-
TOTAL	53,620	+21.2	-191.7	-21.7	-257.5	11,309	3213	212.7

NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 65. UTILITY CONSUMPTION

JP-8 + DF-2/DFM

	Power, kWh	Steam, M lb/hr HP	Steam, M lb/hr MP	Steam, M lb/hr LP	BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	23,991	-	+72.8	+45.9	-153.4	1720	676	35.9
Naphtha Hydrotreating	85	-	-	-	-	24	2	-
Platforming	279	+7.2	-0.1	-	-7.7	160	37	-
Hydrogen Plant (Steam Reforming)	7,021	+221.8	-	-	-642.6	295	2057	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-83.0	-	-	-
Sour Water Treating	352	-	-214.8	-	+214.8	4150	-	-
Fractionation	274	-	-	-19.3	+19.3	393	35	-
Fuel Oil Stabilizer	103	-	-	-	-	209	31	-
TOTAL	46,221	+80.1	-115.1	+29.0	-454.8	9517	3136	210.5

NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 66. PROCESS UNITS CAPACITIES AND CAPITAL INVESTMENTS

	Max. JP-4		JP-4 + DF-2/DFM		Max. JP-8		JP-8 + DF-2/DFM	
	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars
Feed Preparation	100,000	9	100,000	9	100,000	9	100,000	9
LP Hydrotreating (RCD Unibon)	100,000	59	100,000	59	100,000	59	100,000	59
HP Hydrotreating	102,920	97	102,920	97	102,920	97	102,920	97
Hydrocracking (HC Unibon)	94,000	169	91,095	165	99,965	176	94,320	169
Fractionation	-	6	-	4	-	7	-	5
Fuel Gas Treating	-	4	-	4	-	4	-	4
Sulfur Plant	(97.5)	6	(97.5)	6	(97.5)	6	(97.5)	6
Hydrogen Plant (Steam Reforming)	(819.2)	125	(468.2)	79	(835.9)	127	(795.4)	122
Hydrogen Plant (Partial Oxidation)	-	-	(317.1)	114	-	-	-	-
Naphtha Hydrotreating	-	-	-	-	6,485	4	2,875	2
Platforming	-	-	-	-	6,485	11	2,875	6
Sour Water Treating	19,480	10	19,365	10	19,920	10	19,580	10
Fuel Oil Stabilizer	15,360	3	18,265	3	9,400	2	15,040	3
Common Facilities	-	11	-	11	-	11		11
TOTAL PROCESS INVESTMENT		499		561		523		503

Note: Capital Investment as of First Quarter 1981.

TABLE 67. PRODUCT QUALITIES

JP-4 and JP-8 [illegible] Fuels

	JP-4 Military Specs.	Max. JP-4 Case	JP-4 + DF-2/DFM Case	JP-8 Military Specs.	Max. JP-8 Case	JP-8 + DF-2/DFM Case
API Gravity,	45-57	49.6	48.7	37-51	44.3	44.3
Aromatics, vol-%	25 (max)	7.9	8.2	25 (max)	10.0	10.0
Flash Point, °F	-	-	-	100 (min)	> 100	> 100
Freeze Point, °F	-72 (max)	< -72	< -72	-58 (max)	< -58	< -58
Smoke Point, mm	20 (min)	> 20	> 20	20 (min)	26	26
Sulfur, wt-%	0.40 (max)	0.0003	0.0003	0.40 (max)	0.0003	.0003
Naphthelenes, vol-%	-	-	-	3.0 (max)	1.5	1.5
Olefins, vol-%	5.0 (max)	nil	nil	5.0 (max)	nil	nil
Distillation, °F						
IBP	Report	108	111	Report	300	300
10%	Report	179	200	401 (max)	337	337
20%	293 (max)	250	270	Report	361	361
50%	374 (max)	374	381	Report	419	419
90%	473 (max)	473	479	Report	512	512
EP	518 (max)	518	520	572 (max)	550	550

TABLE 68. DF-2 and DFM DIESEL FUELS

	DF-2 Diesel Fuel (Oconus) Specs.	Diesel Fuel Marine Specs.	JP-4 + DF-2/DFM Case	JP-8 + DF-2/DFM Case
Gravity, °API	32.9-41.0	Report	38.4	37.8
Flash Point, °F	133 (Min.)	140 (Min.)	268	288
Cloud Point, °F	9 (Max.)	30 (Max.)	5	5
Pour Point, °F	0 (Max.)	20 (Max.)	0	0
Sulfur, wt-%	0.7 (Max.)	1.0 (Max.)	0.0003	0.0003
Cetane Number	45 (Min.)	-	56	56
Aniline Point, °F	-	Report	198	200
Viscosity:				
cSt at 100°F	1.8-9.5	1.8-4.5	4.4	4.5
Distillation, °F				
50%	Report	-	605	620
90%	675 (Max.)	675 (Max.)	673	675
EP	700 (Max.)	725 (Max.)	700	700

TABLE 69. GASOLINE BLENDS AND QUALITIES

Special Grade -- Unleaded

Gasoline Component	Max. JP-8 Case Gasoline vol-%	Max. JP-8 Case Gasoline BPSD	JP-8 + Diesel Gasoline vol-%	JP-8 + Diesel Gasoline BPSD
Platformate	58.1	5,139	66.4	2,337
Heavy Naphtha	-	-	7.9	280
Light Gasoline	31.4	2,776	12.9	454
Mixed Butanes	10.5	934	12.8	450
TOTAL	100.0	8,849	100.0	3,521

Properties of Gasoline	Military Specs.	Max. JP-8 Gasoline	JP-8 + Diesel Gasoline
API Gravity	-	57.9	54.5
RON Clear	92.0 (Min.)	92.0	92.0
MON Clear	82.0 (Min.)	84.3	83.7
R+M/2	87.0 (Min.)	88.1	87.9
RVP, psi	13.5 (Max.)	13.5	13.5
Sulfur, wt-%	0.10 (Max.)	0.0003	0.0003
Aromatics, vol-%	55.0 (Max.)	42.8	46.3
Distillation (D-1160), °F			
IBP	-	53	84
10%	131 (Max.)	105	129
30%	-	145	171
50%	171 (Min.)-235 (Max.)	183	213
70%	-	245	249
90%	365 (Max.)	292	284
EP	437 (Max.)	342	335

TABLE 70. MAX. JP-4 CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

	MM$/Yr.	MM$/Yr.
A. Refinery Labor		
Direct Labor		
76 operators	2.67	
28 helpers	0.85	
Total Direct Labor	3.52	
Supervision		
25% of Direct Labor	0.88	
Total Operating Labor	4.40	
Overhead		
100% of Operating Labor	4.40	
Total Labor	8.80	8.80
B. Maintenance		
Maintenance Allowance at 3% of Plant Investment		22.92
C. Utilities		
Power: 50,981 kWh at $0.045/kWh	18.09	
600 lb Steam: 211.3 M lb/hr at $0.68/M lb (cost)	1.13	
BF Water: 224.1 M lb/hr at $0.50/M lb	0.88	
Cold Treated Water: 233.8 M lb/hr at $0.07/M lb	0.13	
Cooling Water: 643.4 M gal/hr at $0.03/M gal	0.15	
Total Utilities	20.38	20.38
D. Catalyst Replacement, Solvents and Chemicals		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	2.26	
Hydrogen Plant	1.35	
Total Catalysts, Solvents and Chemicals	8.78	8.78
Total Direct Operating Cost		60.88

TABLE 70. MAX. JP-4 CASE -- ESTIMATED OPERATING COST (Cont'd)

	MM$/Yr.
Indirect Operating Cost	
Local Taxes	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	8.83
Insurance	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	4.41
Total Indirect Operating Cost	13.24
Total Operating Cost	74.12

TABLE 71. JP-4 + DIESEL CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

	MM$/Yr.	MM$/Yr.
A. Refinery Labor		
Direct Labor		
86 operators	3.00	
32 helpers	0.99	
Total Direct Labor	3.99	
Supervision		
25% of Direct Labor	1.00	
Total Operating Labor	4.99	
Overhead		
100% of Operating Labor	4.99	
Total Labor	9.98	9.98
B. Maintenance		
Maintenance Allowance at 3% of Plant Investment		25.62
C. Utilities		
Power: 70,069 kWh at $0.045/kWh	24.86	
600 lb Steam: None	-	
BF Water: 292.1 M lb/hr at $0.50/M lb	1.15	
Cold Treated Water: 232.5 M lb/hr at $0.07/M lb	0.13	
Cooling Water: 1853.1 M gal/hr at $0.03/M gal	0.44	
Total Utilities	26.58	26.58
D. Catalyst Replacement, Solvents and Chemicals		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	1.73	
Hydrogen Plant	1.21	
Total Catalysts, Solvents and Chemicals	8.11	8.11
Total Direct Operating Cost		70.29

TABLE 71. JP-4 + DIESEL CASE -- ESTIMATED OPERATING COST (Cont'd)

	MM$/Yr.
Indirect Operating Cost	
Local Taxes	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	9.70
Insurance	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	4.85
Total Indirect Operating Cost	14.55
Total Operating Cost	84.84

TABLE 72. MAX. JP-8 CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost	MM$/Yr.	MM$/Yr.
A. Refinery Labor		
Direct Labor		
88 operators	3.07	
32 helpers	0.99	
Total Direct Labor	4.06	
Supervision		
25% of Direct Labor	1.02	
Total Operating Labor	5.08	
Overhead		
100% of Operating Labor	5.08	
Total Labor	10.16	10.16
B. Maintenance		
Maintenance Allowance at 3% of Plant Investment		23.97
C. Utilities		
Power: 53,622 kWh at $0.045/kWh	19.02	
600 lb Steam: 192.2 M lb/hr at $0.68/M lb (cost)	1.03	
BF Water: 257.5 M lb/hr at $0.50/M lb	1.02	
Cold Treated Water: 235.1 M lb/hr at $0.07/M lb	0.13	
Cooling Water: 678.6 M gal/hr at $0.03/M gal	0.16	
Total Utilities	21.36	21.36
D. Catalyst Replacement, Solvents and Chemicals		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	2.30	
Hydrogen Plant	1.38	
Naphtha Hydrotreating and Platformer	0.13	
Total Catalysts, Solvents and Chemicals	8.98	8.98
Total Direct Operating Cost		64.47

TABLE 72. MAX. JP-8 CASE -- ESTIMATED OPERATING COST (Cont'd)

	MM$/Yr.
Indirect Operating Cost	
Local Taxes	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	9.20
Insurance	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	4.60
Total Indirect Operating Cost	13.80
Total Operating Cost	78.27

TABLE 73. JP-8 + DIESEL CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

	MM$/Yr.	MM$/Yr.
A. Refinery Labor		
Direct Labor		
88 operators	3.07	
32 helpers	0.99	
Total Direct Labor	4.06	
Supervision		
25% of Direct Labor	1.02	
Total Operating Labor	5.08	
Overhead		
100% of Operating Labor	5.08	
Total Labor	10.16	10.16
B. Maintenance		
Maintenance Allowance at 3% of Plant Investment		23.10
C. Utilities		
Power: 46,222 kWh at $0.045/kWh	16.40	
600 lb Steam: 34.9 M lb/hr at $0.68/M lb (cost)	0.19	
BF Water: 454.8 M lb/hr at $0.50/M lb	1.79	
Cold Treated Water: 235.1 M lb/hr at $0.07/M lb	0.13	
Cooling Water: 571.0 M gal/hr at $0.03/M gal	0.13	
Total Utilities	18.64	18.64
D. Catalyst Replacement, Solvents and Chemicals		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	1.79	
Hydrogen Plant	1.36	
Naphtha Hydrotreater and Platformer	0.05	
Total Catalysts, Solvents and Chemicals	8.37	8.37
Total Direct Operating Cost		60.27

TABLE 73. JP-8 + DIESEL CASE -- ESTIMATED OPERATING COST (Cont'd)

	MM$/Yr.
Indirect Operating Cost	
Local Taxes	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	8.86
Insurance	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	4.43
Total Indirect Operating Cost	13.29
Total Operating Cost	73.56

TABLE 74. CAPITAL INVESTMENT SUMMARY

(Millions of Dollars)

100,000 BPSD Refinery

	Max. JP-4	JP-4 + Diesel	Max. JP-8	JP-8 + Diesel
Process Units Erected Cost	499	561	523	503
Allowance for Offsites	265	293	276	267
Allowance for Fully Paid Royalties and Know-How Fees	20	20	20	20
TOTAL DEPRECIABLE INVESTMENT	784	874	819	790
Initial Catalyst Inventory	25	22	27	23
Working Capital Allowance	93	93	93	92
TOTAL CAPITAL INVESTMENT	902	989	939	905

TABLE 75. COST OF PRODUCTION BREAKDOWN

100,000 BPSD Charge Rate

	Max. JP-4	JP-4 + DF-2/DFM	Max. JP-8	JP-8 + DF-2/DFM
Operating Cost, \$/Bbl of Feed	2.26	2.58	2.38	2.24
Cost of Feed, \$/Bbl	40.00	40.00	40.00	40.00
Capital Charges for 15% DCF Return, \$/Bbl of Feed	9.88	10.84	10.30	9.91
Total Cost of Production, \$/Bbl of Feed	52.14	53.42	52.68	52.15
Total Cost of Liquid Products, \$/Bbl	56.82	58.82	58.80	58.85

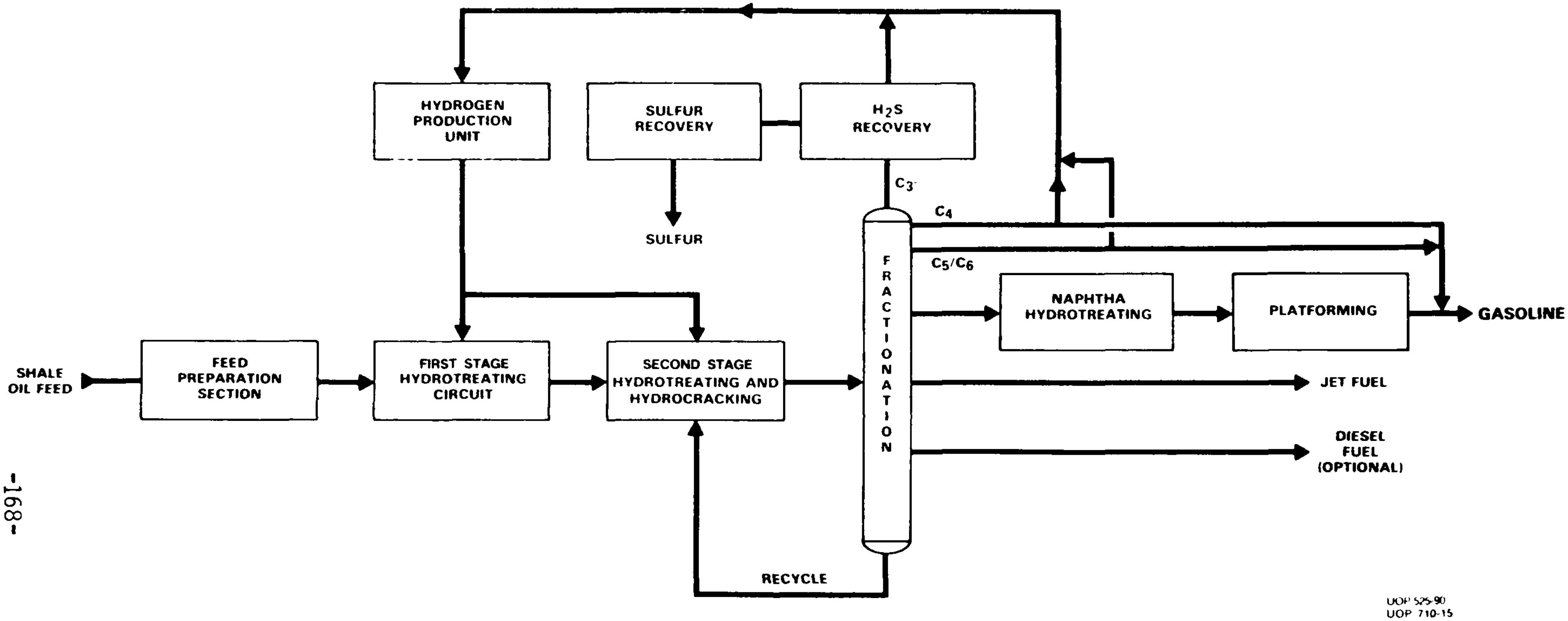

FIGURE 31

UOP SHALE OIL TO FUELS

OVERALL BLOCK FLOW DIAGRAM

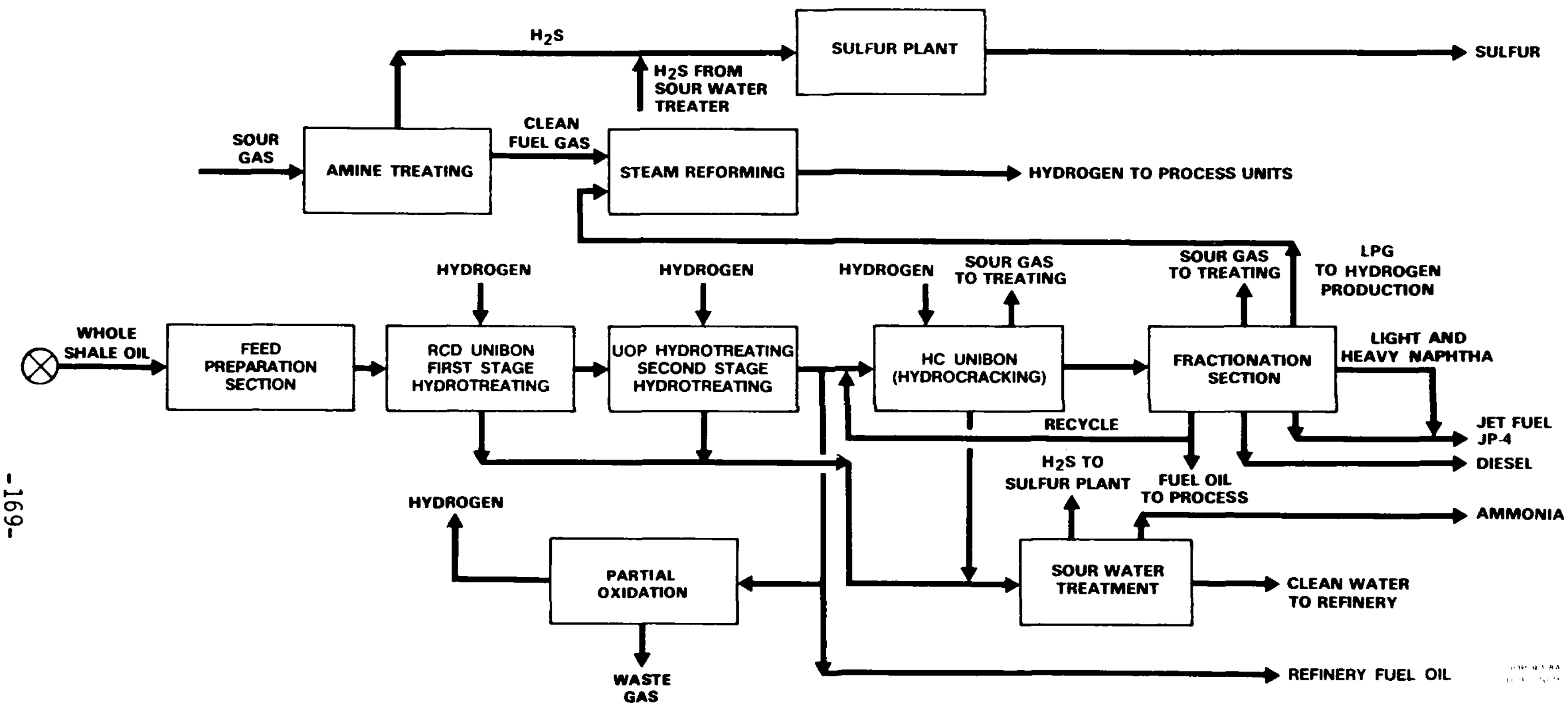

FIGURE 32

PRODUCTION OF JP-4 JET FUEL

BLOCK FLOW DIAGRAM

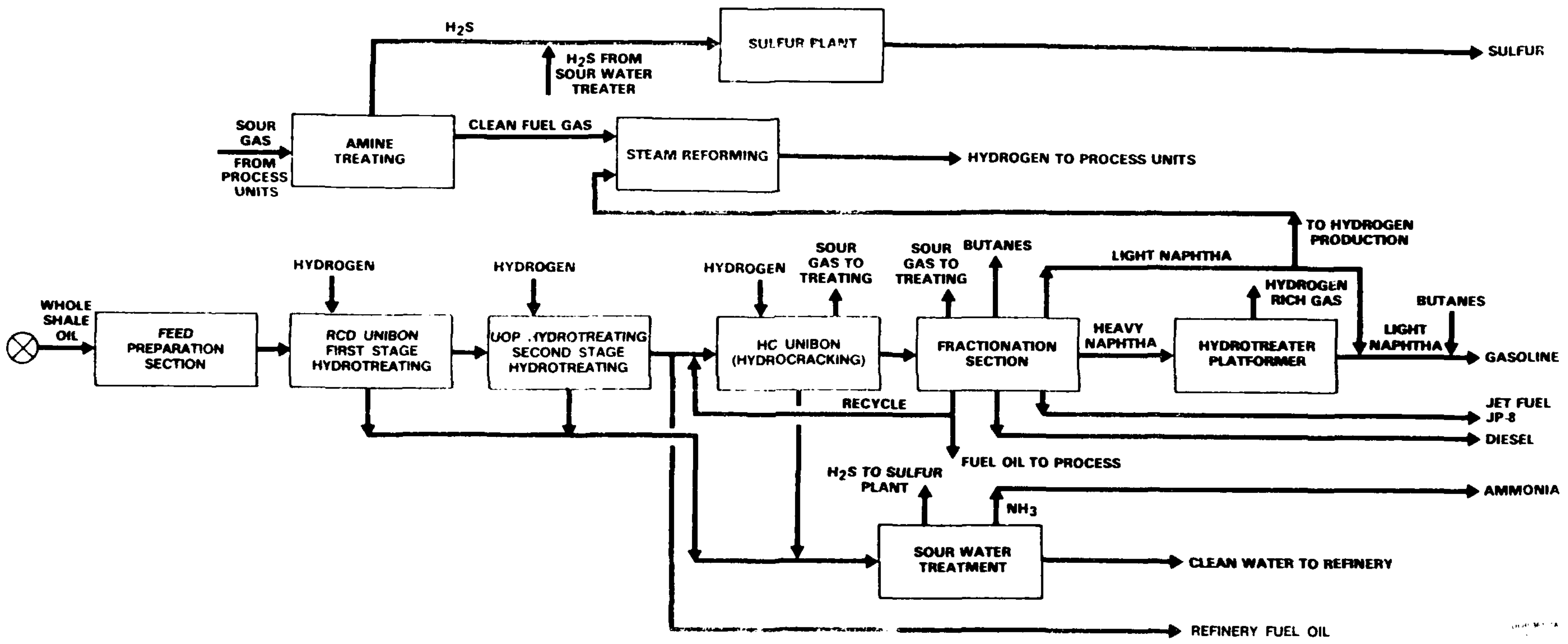

FIGURE 33
PRODUCTION OF JP-8 JET FUEL
BLOCK FLOW DIAGRAM

APPENDIX A

SAMPLE PREPARATION AND ANALYSIS FOR STABILITY/COMPATIBILITY STUDY

A.1 Preparation of Samples

A.1.1 Shale Oil Samples

1. Transfer 1850 cc of representative sample to a one-gallon bottle.

2. Place one-gallon bottle containing sample in sonic bath. Sonify at 80°F while bubbling in N_2 at 5 LHSV for 30 minutes to disperse and deoxygenate sample. Seal under N_2.

3. Send samples for the following analysis stored under N_2.

	Sample Size, g
Distillation (D-1160)	220
Micro C, H, O	1
Sulfur	1
Total N	1
Conradson Carbon	1
C_7 Insolubles	1
Toluene Insolubles	1
Viscosity, Kinematic at 100°F	40
Steam Jet Gum	100
Bromine Number	10
Metals by AAS: As, Fe, Ni, V	25
F 21-51 (300°F Accelerated Fuel Oil Stability Test)	60 (mL)
ASTM D 2274-74 (Oxidation Stability Test)	375
Three Months 110°F Dark Storage Stability	375

A.1.2 Petroleum Crude Oil Sample

1. To each of 3 one-gallon bottles, transfer 1850 cc of representative sample of petroleum crude oil.

2. Sonic disperse and deoxygenate sample as listed in A.1.1.2.

3. Send sample for analysis listed in A.1.1.3.

A.2 Preparation of Shale Oil/Petroleum Crude Oil Blends

1. Blends are prepared from sonic dispersed and deoxygenated samples. Transfer 300 cc ± 1 cc shale oil to 1 gallon bottle. Add 700 cc ± 1 cc petroleum crude oil.

2. Place sample blend in sonic bath. Sonify at 80°F while bubbling in N_2 at 5 LHSV for 5 minutes to disperse and deoxygenate sample. Seal under N_2.

3. Send samples for the following analysis stored under N_2.

	Sample Size, g
C_7 Insolubles	1
Toluene Insolubles	1
Viscosity, Kinematic at 100°F	40
Steam Jet Gum	100
F 21-51 (350°F Accelerated Fuel Oil Stability Test)	60 (mL)
ASTM D 2274-74 (Oxidation Stability Accelerated Method)	375
Three Months 110°F Dark Storage Stability	375

A.3 Three Months 110°F Dark Storage Fuel Oil Stability Test

1. Scope

1.1 This method covers the measurement of the stability of distillate fuel. The fuel is stored in vented Pyrex bottles for three months at 110°F to give an indication of the fuels potential long-term storage stability when stored at lower temperatures.

2. Applicable Documents

2.1 ASTM Standards:

- D 270 Sampling Petroleum and Petroleum Products
- D 2274 Test for Oxidation Stability of Distillate Fuel Oil Accelerated Method
- D 1500 ASTM Color of Petroleum Products
- D 381 ASTM Jet Evaporation, Adherent Gums

3. Summary of Method

3.1 A measured volume of filtered fuel is stored in vented Pyrex bottles for three months at 110°F. After three months he samples are examined for color and sediment.

4. Significance

4.1 This test is the most commonly used accelerated test for distillate fuel oils. Many studies have been made and it has been shown that 13 weeks at 110°F dark storage is equivalent, in most cases, to one year of ambient storage (12.1).

5. Apparatus

5.1 Sample containers are Serum Pyrex Bottles (12.2). The total capacity of the container is 500 mL.

AD-A130 374 USAF SHALE OIL TO FUELS VOLUME 2 PHASES 3 AND4(U) UOP INC DES PLAINES IL PROCESS DIV J G SIKONIA ET AL. JUL 82 AFWAL-TR-81-2116-VOL-2 F33615-78-C-2079 3/4

UNCLASSIFIED F/G 21/4 NL

5.2 A Miracle Top Box (12.3) with cover is used to store samples. Ends are open to allow ventilation.

5.3 A hot room is used to store samples. Temperature is thermostatically controlled to maintain a temperature of 110° ± 1°F.

5.4 Drying oven, maintained at 194° ± 2°F.

5.5 Filter holder, Millipore, Hydrosol Stainless, 47 mm, XX20 047 20.

5.6 Flash 21 filtering with side tube.

5.7 Petri dish.

6. Reagents and Materials

6.1 Filter, 0.8 μ Millipore Type AA.

6.2 Hydrocarbon solvent, n-heptane, 99% minimum purity, (Phillips Petroleum Company, or equivalent).

6.3 All equipment required to determine color by ASTM Method D 1500 (if desired).

7. Sampling Procedure

7.1 A sample for testing will be procured by the method outlined in ASTM Method D 270. Sample containers should preferably be 1-gallon or larger metal can. Sample containers should be rinsed with Adherent Insoluble Solvent (equal parts of reagent grade toluene, acetone, methanol), dried and then nitrogen filled. Samples should be stored at reduced temperature, 33° to 45°F, prior to use.

A.3 Three Months 110°F Dark Storage Fuel Oil Stability Test

1. Scope

1.1 This method covers the measurement of the stability of distillate fuel. The fuel is stored in vented Pyrex bottles for three months at 110°F to give an indication of the fuels potential long-term storage stability when stored at lower temperatures.

2. Applicable Documents

2.1 ASTM Standards:

- D 270 Sampling Petroleum and Petroleum Products
- D 2274 Test for Oxidation Stability of Distillate Fuel Oil Accelerated Method
- D 1500 ASTM Color of Petroleum Products
- D 381 ASTM Jet Evaporation, Adherent Gums

3. Summary of Method

3.1 A measured volume of filtered fuel is stored in vented Pyrex bottles for three months at 110°F. After three months the samples are examined for color and sediment.

4. Significance

4.1 This test is the most commonly used accelerated test for distillate fuel oils. Many studies have been made and it has been shown that 13 weeks at 110°F dark storage is equivalent, in most cases, to one year of ambient storage (12.1).

5. Apparatus

5.1 Sample containers are Serum Pyrex Bottles (12.2). The total capacity of the container is 500 mL.

8. <u>Preparation of Apparatus</u>

8.1 Sample storage bottles. Rinse bottle with Adherent Insoluble solvent (equal parts of reagent grade toluene, acetone, methanol) and dry. If any stains are present, treat bottle first with chromic acid cleaning solution, rinse with water and dry.

8.2 Equilibrate the filter in a petri dish next to the balance for 30 minutes. Weigh filter to nearest 0.1 mg and retain for sample analysis. A "moisture blank" is run to correct for atmospheric moisture. Place the "moisture blank" filter in the petri dish, dry for 1 hour in an oven maintained at 194° ± 2°F. After drying place in desiccator (without desiccant) for at least 1 hour. One "moisture blank" filter is run for every four samples analyzed. The "moisture blank" filter should be weighed whenever the other four test filters are weighed and its change of weight subtracted from the level sample weight to correct for atmospheric moisture. The "moistur; blank" filter is equilibrated in a petri dish next to the balance for 30 minutes before weighing.

9. <u>Preparation of Sample</u>

9.1 Prior to storage, the fuel oil shall be filtered through Whatman No. 2 filter paper at room temperature. Determine ASTM D 1500 color on unaged filtered fuel.

10. <u>Procedure</u>

10.1 Place 350 mL of filtered fuel in a bottle. Label storage bottle. Place in Miracle Top Box (Sec. 5.2) and store in hot room at 110° ± 1°F for 3 month dark storage.

10.2 At the end of the 3 month storage period remove the sample and cool to room temperature. Filter the aged sample under vacuum

(20-25 mm H_2O) through a weighed filter (0.8 μ Millipore Type AA) in a millipore filter holder. Remove the filtrate and determine ASTM D 1500 color on aged filtered fuel. Rinse the storage bottle with n-heptane to remove all traces of fuel from the bottle, transferring each wash to the filter holder. Wash the filter paper and holder with n-heptane until free of fuel oil, using vacuum. The rinse filtrate can be discarded.

10.3 Transfer the filter to a petri dish, dry for 1 hour in an oven maintained at 194° ± 2°F. After drying place in desiccator (without desiccant) for at least 1 hour. Equilibrate the filter together with the "moisture blank" next to balance for 30 minutes. Weight to nearest 0.1 mg.

11. Calculations

11.1 Calculate the total sediment formation in milligrams per 100 mL after aging as follows:

$$A = \frac{B}{C} \times 100$$

where:

A = Total sediment, mg/100 mL

B = Weight of filterable sediment corrected for moisture using the "moisture blank"

C = Fuel placed in storage bottle, mL

12. References

12.1 Distillate Fuel Storage Stability Research conducted at Petroleum Experimental Station Bureau of Mines, Bartlesville, Oklahoma -- Done for Western Petroleum Refining Association, October, 1958.

12.2 Bottle, Storage, (Centrifuge, original form) Pyrex, Corning, New Jersey, No. 1260; CGW code 423290, 500 mL cap. 73 mm dia., 173 mm high.

12.3 Miracle Box No. 15, Paige Co., 432 Park Avenue South, New York, New York 10016.

A.4 Modification for Three Months 110°F Dark Storage Fuel Oil Stability Test

1. Store samples in vented Pyrex bottle for three months at 110°F as per Three Months 110°F Dark Storage Stability Test.

2. After three months storage, place sample in sonic bath for 30 minutes.

3. Send samples for the following analysis:

   C_7 Insolubles
   Toluene Insolubles
   Kinematic Viscosity at 100°F

4. Pour the remainder of sample into the bottle and store under N_2. Wash the sample containers with three rinses (of about 50 mL each) of cyclohexane. Discard cyclohexane rinse solution.

5. Dissolve any adherent gum on sample container wall with adherent insoluble solvent (equal parts of toluene, acetone and methanol). Determine the adherent insoluble content by evaporating the solvent at 320°F (160°C) by the air-jet method described in Method D 381. Obtain weight of adherent insolubles in mg to 0.1 mg.

A.5 Modification for F 21-61 (300°F Accelerated Fuel Oil Stability Test)

1. Follow steps (3), (4), and (5) of F 21-61 method.

2. After sample has cooled (step 5), place in sonic bath for 30 minutes.

3. Send sample for the following analysis:

    C_7 Insolubles
    Toluene Insolubles
    Kinematic Viscosity

4. Pour the remainder of sample into the bottle and store under N_2.

A.6 Modification for ASTM D 2274-74

1. Follow step (8.3) of ASTM D 2274-74 method.

2. After test, remove sample from bath and pour it into a 500 mL Erlenmeyer flask. Place the flask in a sonic bath for 30 minutes.

3. Sample for the following analysis:

    C_7 Insolubles
    Toluene Insolubles
    Kinematic Viscosity at 100°F

4. Pour the remainder of sample into the bottle and store under N_2.

5. Wash the sample container used in the ASTM D 2274-74 test and oxygen delivery tube with three rinsings (of about 50 mL each) of cyclohexane. Discard cyclohexane rinse solution.

6. Dissolve any adherent gum on container walls and oxygen delivery tube with the adherent insoluble solvent (equal parts of toluene, acetone and methanol). Determine the adherent insolubles content by evaporating the solvent at 320°F (160°C) by the air-jet method described in Method D 381. Obtain weight of adherent insolubles in mg to nearest 0.1 mg.

A.7 Standard Analytical Methods

Method Title	UOP Method No.*	ASTM Method No.**
Distillation		D 1160
Heptane Insoluble Matter - Membrane Filter	U 614	
Toluene Insoluble Matter - Membrane Filter	Mod. U 614	
Conradson Carbon Residue of Petroleum Products		D 189
Viscosity, Kinematic at 100°F		D 445
Hydrogen and Carbon (Micro)	U 638	
Oxygen, Total, in Organic Materials	U 649	
Sulfur in Petroleum Products		D 1512
Nitrogen by Acid Extraction & Kjeldahl (495)	U 384	
Steam Jet Gum		D 381
300°F Accelerated Fuel Oil Stability Test	Mod. DuPont F 21-61	
Oxidation Stability of Distillate Fuel Oil		D 2274
Three Months 110°F Dark Storage Stability Test	***	
Metals in Petroleum Oil by AAS	800	
Bromine Number of Petroleum Distillates and Commerical Aliphatic Olefins by Electrometric Titration		D 1159
Modified Coulometric Sulfur	U 731	

* "UOP Laboratory Test Methods for Petroleum and Its Products", UOP Process Division, Des Plaines, Illinois.

** "1980 Annual Book ASTM Standards", American Society for Testing and Materials, Philadelphia, PA; 1980.

*** UOP Laboratory Test Method, not yet finalized.

Appendix B.1

MAXIMUM JP-4 CASE -- PROFORMA FINANCIAL STATEMENT

ECONOMIC EVALUATION MODEL — USAF SHALE OIL STUDY — MAX.JP4-15% ROI

RUN NUMBER 2 — PROFORMA FINANCIAL STATEMENT — PAGE 1 -- 1

ALL $ VALUES IN MILLIONS YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	865.76	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	208.76	417.51	417.51	417.51	417.51	417.51	417.51	417.51	417.51	417.51
OPERATING LABOR	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80
UTILITY COST	10.19	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38
MAINTENANCE COST	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92
CAT+CHEM COST	4.39	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78
DIRECT MFG EXPENSE	46.30	60.88	60.88	60.88	60.88	60.88	60.88	60.88	60.88	60.88
INSURANCE	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41
PROPERTY TAX	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83
INDIRECT MFG EXPENSE	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24
DEPRECIATION	112.00	103.38	94.77	86.15	77.54	68.92	60.31	51.69	43.08	34.46
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	23.26	226.05	234.67	243.28	251.90	260.51	269.13	277.74	286.36	294.97
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	23.26	226.05	234.67	243.28	251.90	260.51	269.13	277.74	286.36	294.97
CURRENT TAX	11.63	113.03	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
TAX CREDITS	10.47	79.82	0.	0.	0.	0.	0	0.	0.	0.
TAXES PAYABLE	1.16	33.20	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
NET AFTER TAX INCOME	22.10	192.85	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
OPERATING CASH FLOW	134.10	296.23	212.10	207.79	203.49	199.18	194.87	190.56	186.26	181.95
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	134.10	296.23	212.10	207.79	203.49	199.18	194.87	190.56	186.26	181.95

ECONOMIC EVALUATION MODEL — USAF SHALE OIL STUDY — MAX.JP4-15% ROI

RUN NUMBER 2 — PROFORMA FINANCIAL STATEMENT — PAGE 1 - 2

ALL $ VALUES IN MILLIONS

YEAR	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	417.51	417.51	417.51	417.51	417.51	417.51
OPERATING LABOR	8.80	8.80	8.80	8.80	8.80	8.80
UTILITY COST	20.38	20.38	20.38	20.38	20.38	20.38
MAINTENANCE COST	22.92	22.92	22.92	22.92	22.92	22.92
CAT+CHEM COST	8.78	8.78	8.78	8.78	8.78	8.78
DIRECT MFG EXPENSE	60.88	60.88	60.88	60.88	60.88	60.88
INSURANCE	4.41	4.41	4.41	4.41	4.41	4.41
PROPERTY TAX	8.83	8.83	8.83	8.83	8.83	8.83
INDIRECT MFG EXPENSE	13.24	13.24	13.24	13.24	13.24	13.24
DEPRECIATION	25.85	17.23	8.62			
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	303.59	312.20	320.82	329.44	329.44	329.44
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	303.59	312.20	320.82	329.44	329.44	329.44
CURRENT TAX	151.79	156.10	160.41	164.72	164.72	164.72
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	151.79	156.10	160.41	164.72	164.72	164.72
NET AFTER TAX INCOME	151.79	156.10	160.41	164.72	164.72	164.72
OPERATING CASH FLOW	177.64	173.33	169.03	164.72	164.72	164.72
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						118.00
NET CASH FLOW	177.64	173.33	169.03	164.72	164.72	164.72

USAF SHALE OIL STUDY

ECONOMIC EVALUATION MODEL　　　　MAX.JP4-15% ROI
RUN NUMBER 2　　　　PROFITABILITY SUMMARY　　　　PAGE 2 - 1

ALL $ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS	4.26
AFTER TAX DISCOUNTED RATE OF RETURN ON EQUITY %	15.00
AFTER TAX DISCOUNTED RATE OF RETURN ON PROJECT %	15.00
NET PRESENT VALUE @15%: $MM	101.09
N.P.V. INDEX @15%	0.11

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ECONOMIC EVALUATION MODEL
RUN NUMBER 2

BASIS FOR STUDY
PROFITABILITY SUMMARY

MAX.JP4-15% ROI

ALL $ VALUES IN MILLIONS

ECONOMIC PARAMETERS

PROJECT LIFE:YEARS	16
CONSTR PERIOD:YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

BASE FEED PRICES

SHALE OIL	40.00

BASE PRODUCT PRICES

JET FUEL $/BBL	56.82
AMMONIA $/ST	155.00
SULFUR $/LT	105.00

BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST&CHEMICALS	25.00
ROYALTY & FEES	0.

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

USAF SHALE OIL STUDY

INVESTMENT SUMMARY

MAX.JP4-15% ROI

PAGE 4 - 1

ALL $ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT	784.00			
CONST. INFLATION FACTOR	1.000			
INTEREST RATE: %	0.000			
YEAR	1982	1983	1984	
% COMPLETION FOR YR	25.00	50.00	25.00	
PLANT INVESTMENT				
. CAPITAL INVESTMENT	196.00	392.00	196.00	
. CONST. COST INFLATION	-0.00	-0.00	-0.00	
. CONST. COST FOR YEAR	196.00	392.00	196.00	
TOTAL DEPRECIABLE INV.				784.00
OTHER INVESTMENT				
. LAND				0.
. INITIAL CAT.&CHEM.				25.00
. ROYALTY & FEES				0.
SUBTOTAL				25.00
WORKING CAPITAL				
. RAW MATERIALS				93.00
. ACCOUNTS RECEIVABLE				0.
. ACCOUNTS PAYABLE				0.
. NOBLE METALS				0.
. INT ON CONSTRUCTION	0.	0.	0.	
TOTAL CONST INTEREST				0.
SUBTOTAL				93.00
TOTAL INVESTMENT				902.00

ECONOMIC EVALUATION MODEL
MAX.JP4-15% ROI
USAF SHALE OIL STUDY
RUN NUMBER 2
PRODUCTION SUMMARY
PAGE 5 - 1
ALL $ VALUES IN MILLIONS

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR										
JET FUEL (BBLS)	15.07	30.14	30.14	30.14	30.14	30.14	30.14	30.14	30.14	30.14
AMMONIA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT										
JET FUEL $/BBL	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR										
JET FUEL	856.42	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85
AMMONIA	2.86	5.72	5.72	5.72	5.72	5.72	5.72	5.72	5.72	5.72
SULFUR	0.83	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66

ECONOMIC EVALUATION MODEL

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

MAX.JP4-15% ROI

YEAR	1995	1996	1997	1998	1999	2000
	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR						
JET FUEL (BBLS)	30.14	30.14	30.14	30.14	30.14	30.14
AMMONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT						
JET FUEL $/BBL	56.82	56.82	56.82	56.82	56.82	56.82
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR						
JET FUEL	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85
AMMONIA	5.72	5.72	5.72	5.72	5.72	5.72
SULFUR	1.66	1.66	1.66	1.66	1.66	1.66

Appendix B.2

JP-4 PLUS DIESEL CASE -- PROFORMA FINANCIAL STATEMENT

ECONOMIC EVALUATION MODEL | JP4+DIESEL-15% ROI

USAF SHALE OIL STUDY
PROFORMA FINANCIAL STATEMENT

RUN NUMBER 2 | PAGE 1 - 1

ALL $ VALUES IN MILLIONS YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	886.76	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	229.76	459.53	459.53	459.53	459.53	459.53	459.53	459.53	459.53	459.53
OPERATING LABOR	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98
UTILITY COST	13.29	26.58	26.58	26.58	26.58	26.58	26.58	26.58	26.58	26.58
MAINTENANCE COST	25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62
CAT+CHEM COST	4.06	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11
DIRECT MFG EXPENSE	52.94	70.29	70.29	70.29	70.29	70.29	70.29	70.29	70.29	70.29
INSURANCE	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85
PROPERTY TAX	9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70
INDIRECT MFG EXPENSE	14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55
DEPRECIATION	124.86	115.25	105.65	96.04	86.44	76.84	67.23	57.63	48.02	38.42
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	23.46	245.49	255.10	264.70	274.30	283.91	293.51	303.12	312.72	322.33
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	23.46	245.49	255.10	264.70	274.30	283.91	293.51	303.12	312.72	322.33
CURRENT TAX	11.73	122.75	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16
TAX CREDITS	10.56	88.43	0.	0.	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	1.17	34.32	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16
NET AFTER TAX INCOME	22.29	211.18	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16
OPERATING CASH FLOW	147.15	326.43	233.20	228.39	223.59	218.79	213.99	209.18	204.38	199.58
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	147.15	326.43	233.19	228.39	223.59	218.79	213.99	209.18	204.38	199.58

ECONOMIC EVALUATION MODEL

RUN NUMBER 2

USAF SHALE OIL STUDY
PROFORMA FINANCIAL STATEMENT

JP4+DIESEL-15% ROI

PAGE 1 - 2

ALL $ VALUES IN MILLIONS

YEAR	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	459.53	459.53	459.53	459.53	459.53	459.53
OPERATING LABOR	9.98	9.98	9.98	9.98	9.98	9.98
UTILITY COST	26.58	26.58	26.58	26.58	26.58	26.58
MAINTENANCE COST	25.62	25.62	25.62	25.62	25.62	25.62
CAT+CHEM COST	8.11	8.11	8.11	8.11	8.11	8.11
DIRECT MFG EXPENSE	70.29	70.29	70.29	70.29	70.29	70.29
INSURANCE	4.85	4.85	4.85	4.85	4.85	4.85
PROPERTY TAX	9.70	9.70	9.70	9.70	9.70	9.70
INDIRECT MFG EXPENSE	14.55	14.55	14.55	14.55	14.55	14.55
DEPRECIATION	28.81	19.21	9.61			
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	331.93	341.53	351.14	360.74	360.74	360.74
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	331.93	341.53	351.14	360.74	360.74	360.74
CURRENT TAX	165.97	170.77	175.57	180.37	180.37	180.37
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	165.97	170.77	175.57	180.37	180.37	180.37
NET AFTER TAX INCOME	165.96	170.77	175.57	180.37	180.37	180.37
OPERATING CASH FLOW	194.78	189.98	185.17	180.37	180.37	180.37
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						115.00
NET CASH FLOW	194.78	189.98	185.17	180.37	180.37	180.37

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                                        USAF SHALE OIL STUDY
ECONOMIC EVALUATION MODEL                                                        JP4+DIESEL-15% ROI
RUN NUMBER      2                     PROFITABILITY SUMMARY                                          PAGE   2 - 1

ALL $ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS                4.24

AFTER TAX DISCOUNTED
RATE OF RETURN ON EQUITY %          15.00

AFTER TAX DISCOUNTED
RATE OF RETURN ON PROJECT %         15.00

NET PRESENT VALUE @15%: $MM        111.05

N.P.V. INDEX      @15%               0.11

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ECONOMIC EVALUATION MODEL
RUN NUMBER 2

BASIS FOR STUDY
PROFITABILITY SUMMARY

JP4+DIESEL-15% ROI
PAGE 3 - 1

ALL $ VALUES IN MILLIONS

ECONOMIC PARAMETERS

PROJECT LIFE:YEARS	16
CONSTR PERIOD:YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

BASE FEED PRICES

SHALE OIL	40.00

BASE PRODUCT PRICES

JET FUEL $/BBL	58.82
AMMONIA $/ST	155.00
SULFUR $/LT	105.00

BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST&CHEMICALS	22.00
ROYALTY & FEES	0.

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

USAF SHALE OIL STUDY
INVESTMENT SUMMARY

JP4+DIESEL-15% ROI
PAGE 4 - 1

ALL $ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT	874.00			
CONST. INFLATION FACTOR	1.000			
INTEREST RATE: %	0.000			
YEAR	1982	1983	1984	
% COMPLETION FOR YR	25.00	50.00	25.00	
PLANT INVESTMENT				
. CAPITAL INVESTMENT	218.50	437.00	218.50	
. CONST. COST INFLATION	-0.00	-0.00	-0.00	
. CONST. COST FOR YEAR	218.50	437.00	218.50	
TOTAL DEPRECIABLE INV.				874.00
OTHER INVESTMENT				
. LAND				0.
. INITIAL CAT.&CHEM.				22.00
. ROYALTY & FEES				0.
SUBTOTAL				22.00
WORKING CAPITAL				
. RAW MATERIALS				93.00
. ACCOUNTS RECEIVABLE				0.
. ACCOUNTS PAYABLE				0.
. NOBLE METALS				0.
. INT ON CONSTRUCTION	0.	0.	0.	
TOTAL CONST INTEREST				0.
SUBTOTAL				93.00
TOTAL INVESTMENT				989.00

ECONOMIC EVALUATION MODEL

JP4+DIESEL-15% ROI

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

PAGE 5 - 1

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR										
JET FUEL (BBLS)	14.92	29.84	29.84	29.84	29.84	29.84	29.84	29.84	29.84	29.84
AMMONIA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT										
JET FUEL $/BBL	58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR										
JET FUEL	877.43	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86
AMMONIA	2.96	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92
SULFUR	0.86	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

ECONOMIC EVALUATION MODEL

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

JP4+DIESEL-15% ROI

PAGE 5 - 2

YEAR	1995	1996	1997	1998	1999	2000
	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR						
JET FUEL (BBLS)	29.84	29.84	29.84	29.84	29.84	29.84
AMMONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT						
JET FUEL $/BBL	58.82	58.82	58.82	58.82	59.82	58.82
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR						
JET FUEL	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86
AMMONIA	5.92	5.92	5.92	5.92	5.92	5.92
SULFUR	1.71	1.71	1.71	1.71	1.71	1.71

Appendix B.3

MAXIMUM JP-8 CASE -- PROFORMA FINANCIAL STATEMENT

ECONOMIC EVALUATION MODEL — MAX.JP8-15% ROI

RUN NUMBER 2 — USAF SHALE OIL STUDY PROFORMA FINANCIAL STATEMENT — PAGE 1 - 1

ALL $ VALUES IN MILLIONS

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	874.55	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	217.55	435.10	435.10	435.10	435.10	435.10	435.10	435.10	435.10	435.10
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	10.68	21.36	21.36	21.36	21.36	21.36	21.36	21.36	21.36	21.36
MAINTENANCE COST	23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97
CAT+CHEM COST	4.49	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98
DIRECT MFG EXPENSE	49.30	64.47	64.47	64.47	64.47	64.47	64.47	64.47	64.47	64.47
INSURANCE	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
PROPERTY TAX	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20
INDIRECT MFG EXPENSE	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80
DEPRECIATION	117.00	108.00	99.00	90.00	81.00	72.00	63.00	54.00	45.00	36.00
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	23.50	234.88	243.88	252.88	261.88	270.88	279.88	288.88	297.88	306.88
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	23.50	234.88	243.88	252.88	261.88	270.88	279.88	288.88	297.88	306.88
CURRENT TAX	11.75	117.44	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44
TAX CREDITS	10.58	83.41	0.	0.	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	1.17	34.02	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44
NET AFTER TAX INCOME	22.33	200.85	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44
OPERATING CASH FLOW	139.33	308.85	220.94	216.44	211.94	207.44	202.94	198.44	193.94	189.44
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	139.33	308.85	220.94	216.44	211.94	207.44	202.94	198.44	193.94	189.44

ECONOMIC EVALUATION MODEL

RUN NUMBER 2

USAF SHALE OIL STUDY
PROFORMA FINANCIAL STATEMENT

MAX.JP8-15% ROI

PAGE 1 -

ALL $ VALUES IN MILLIONS

YEAR	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	435.10	435.10	435.10	435.10	435.10	435.10
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	21.36	21.36	21.36	21.36	21.36	21.36
MAINTENANCE COST	23.97	23.97	23.97	23.97	23.97	23.97
CAT+CHEM COST	8.98	8.98	8.98	8.98	8.98	8.98
DIRECT MFG EXPENSE	64.47	64.47	64.47	64.47	64.47	64.47
INSURANCE	4.60	4.60	4.60	4.60	4.60	4.60
PROPERTY TAX	9.20	9.20	9.20	9.20	9.20	9.20
INDIRECT MFG EXPENSE	13.80	13.80	13.80	13.80	13.80	13.80
DEPRECIATION	27.00	18.00	9.00			
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	315.88	324.88	333.88	342.88	342.88	342.88
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	315.88	324.88	333.88	342.88	342.88	342.88
CURRENT TAX	157.94	162.44	166.94	171.44	171.44	171.44
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	157.94	162.44	166.94	171.44	171.44	171.44
NET AFTER TAX INCOME	157.94	162.44	166.94	171.44	171.44	171.44
OPERATING CASH FLOW	184.94	180.44	175.94	171.44	171.44	171.44
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						120.00
NET CASH FLOW	184.94	180.44	175.94	171.44	171.44	171.44

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

USAF SHALE OIL STUDY

PROFITABILITY SUMMARY

MAX.JP8-15% ROI

ALL $ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS	4.26
AFTER TAX DISCOUNTED RATE OF RETURN ON EQUITY %	15.00
AFTER TAX DISCOUNTED RATE OF RETURN ON PROJECT %	15.00
NET PRESENT VALUE @15%: $MM	105.25
N.P.V. INDEX @15%	0.11

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ECONOMIC EVALUATION MODEL
RUN NUMBER 2

BASIS FOR STUDY

PROFITABILITY SUMMARY

MAX.JP8-15% ROI

ALL $ VALUES IN MILLIONS

ECONOMIC PARAMETERS

PROJECT LIFE:YEARS	16
CONSTR PERIOD:YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

BASE FEED PRICES

SHALE OIL	40.00

BASE PRODUCT PRICES

JET FUEL $/BBL	58.80
AMMONIA $/ST	155.00
SULFUR $/LT	105.00

BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST&CHEMICALS	27.00
ROYALTY & FEES	0.

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

USAF SHALE OIL STUDY

INVESTMENT SUMMARY

MAX.JP8-15% ROI

PAGE 4 - 1

ALL $ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT	81?.00			
CONST. INFLATION FACTOR	1 000			
INTEREST RATE: %	0.000			
YEAR	1982	1983	1984	
% COMPLETION FOR YR	25.00	50.00	25.00	
PLANT INVESTMENT				
. CAPITAL INVESTMENT	204.75	409.50	204.75	
. CONST. COST INFLATION	-0.00	-0.00	-0.00	
. CONST. COST FOR YEAR	204.75	409.50	204.75	
TOTAL DEPRECIABLE INV.				819.00
OTHER INVESTMENT				
. LAND				0.
. INITIAL CAT.&CHEM.				27.00
. ROYALTY & FEES				0.
SUBTOTAL				27.00
WORKING CAPITAL				
. RAW MATERIALS				93.00
. ACCOUNTS RECEIVABLE				0.
. ACCOUNTS PAYABLE				0.
. NOBLE METALS				0.
. INT ON CONSTRUCTION	0.	0.	0.	
TOTAL CONST INTEREST				0.
SUBTOTAL				93.00
TOTAL INVESTMENT				939.00

ECONOMIC EVALUATION MODEL

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

MAX.JP8-15% ROI

PAGE 5 - 1

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR										
JET FUEL (BBLS)	14.72	29.43	29.43	29.43	29.43	29.43	29.43	29.43	29.43	29.43
AMMONIA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT										
JET FUEL $/BBL	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR										
JET FUEL	865.19	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38
AMMONIA	2.97	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	0.86	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

ECONOMIC EVALUATION MODEL

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

MAX.JP8-15% ROI

PAGE 5 - 2

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

YEAR	1995	1996	1997	1998	1999	2000
	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR						
JET FUEL (BBLS)	29.43	29.43	29.43	29.43	29.43	29.43
AMMONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT						
JET FUEL $/BBL	58.80	58.80	58.80	58.80	58.80	58.80
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR						
JET FUEL	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38
AMMONIA	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	1.71	1.71	1.71	1.71	1.71	1.71

Appendix B.4

JP-8 PLUS DIESEL CASE -- PROFORMA FINANCIAL STATEMENT

ECONOMIC EVALUATION MODEL — JP8+DIESEL-15% ROI

USAF SHALE OIL STUDY
PROFORMA FINANCIAL STATEMENT

RUN NUMBER 2 — PAGE 1 - 1

ALL $ VALUES IN MILLIONS YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	865.94	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	208.94	417.88	417.88	417.88	417.88	417.88	417.88	417.88	417.88	417.88
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	9.32	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64
MAINTENANCE COST	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10
CAT+CHEM COST	4.18	8.37	8.37	8.37	8.37	8.37	8.37	8.37	8.37	8.37
DIRECT MFG EXPENSE	46.77	60.27	60.27	60.27	60.27	60.27	60.27	60.27	60.27	60.27
INSURANCE	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
PROPERTY TAX	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86
INDIRECT MFG EXPENSE	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29
DEPRECIATION	112.86	104.18	95.49	86.81	78.13	69.45	60.77	52.09	43.41	34.73
INTEREST ON W. CAPITAL	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80
TAXABLE INCOME	22.23	226.34	235.02	243.70	252.38	261.06	269.75	278.43	287.11	295.79
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	22.23	226.34	235.02	243.70	252.38	261.06	269.75	278.43	287.11	295.79
CURRENT TAX	11.11	113.17	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
TAX CREDITS	10.00	80.59	0.	0.	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	1.11	32.58	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
NET AFTER TAX INCOME	21.12	193.76	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
OPERATING CASH FLOW	133.97	297.93	213.00	208.66	204.32	199.98	195.64	191.30	186.96	182.62
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	133.97	297.93	213.00	208.66	204.32	199.98	195.64	191.30	186.96	182.62

ECONOMIC EVALUATION MODEL | JP8+DIESEL-15% ROI

RUN NUMBER 2

USAF SHALE OIL STUDY
PROFORMA FINANCIAL STATEMENT

PAGE 1 - 2

ALL $ VALUES IN MILLIONS

YEAR	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	417.88	417.88	417.88	417.88	417.88	417.88
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	18.64	18.64	18.64	18.64	18.64	18.64
MAINTENANCE COST	23.10	23.10	23.10	23.10	23.10	23.10
CAT+CHEM COST	8.37	8.37	8.37	8.37	8.37	3.37
DIRECT MFG EXPENSE	60.27	60.27	60.27	60.27	60.27	60.27
INSURANCE	4.43	4.43	4.43	4.43	4.43	4.43
PROPERTY TAX	8.86	8.86	8.86	8.86	8.86	8.86
INDIRECT MFG EXPENSE	13.[illegible]	13.29	13.29	13.29	13.29	13.29
DEPRECIATION	26.04	17.36	6.68			
INTEREST ON W. CAPITAL	13.80	13.80	13.80	13.80	13.80	13.80
TAXABLE INCOME	304.47	313 15	321.83	330.51	330.51	330.51
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	304.47	313.13	321.83	330.51	330.51	330.51
CURRENT TAX	152.24	156.58	160.92	165.26	165.26	165.26
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	152.24	156.58	160.92	165.26	165.26	165.26
NET AFTER TAX INCOME	152.24	156.58	160.92	165.26	165.26	165.26
OPERATING CASH FLOW	178.28	173.94	169.60	165.26	165.26	165.26
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						115.00
NET CASH FLOW	178.28	173.94	169.60	165.26	165.26	165.26

USAF SHALE OIL STUDY

PROFITABILITY SUMMARY

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

JP8+DIESEL-15% ROI

PAGE 2 - 1

ALL $ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS	4.26
AFTER TAX DISCOUNTED RATE OF RETURN ON EQUITY %	15.00
AFTER TAX DISCOUNTED RATE OF RETURN ON PROJECT %	15.00
NET PRESENT VALUE @15%: $MM	101.44
N.P.V. INDEX @15%	0.11

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ECONOMIC EVALUATION MODEL   BASIS FOR STUDY   JP8+DIESEL-15% ROI
RUN NUMBER 2   PROFITABILITY SUMMARY   PAGE 3 - 1

ALL $ VALUES IN MILLIONS

ECONOMIC PARAMETERS

PROJECT LIFE:YEARS	16
CONSTR PERIOD:YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

BASE FEED PRICES

SHALE OIL	40.00

BASE PRODUCT PRICES

JET FUEL $/BBL	58.85
AMMONIA $/ST	155.00
SULFUR $/LT	105.00

BASE WORKING CAPITAL

RAW MATERIALS	92.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST&CHEMICALS	23.00
ROYALTY & FEES	0.

ECONOMIC EVALUATION MODEL
RUN NUMBER 2

USAF SHALE OIL STUDY

INVESTMENT SUMMARY

JP8+DIESEL-15% ROI

PAGE 4 - 1

ALL $ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT	790.00			
CONST. INFLATION FACTOR	1.000			
INTEREST RATE: %	0.000			
YEAR	1982	1983	1984	
% COMPLETION FOR YR	25.00	50.00	25.00	
PLANT INVESTMENT				
. CAPITAL INVESTMENT	197.50	395.00	197.50	
. CONST. COST INFLATION	-0.00	-0.00	-0.00	
. CONST. COST FOR YEAR	197.50	395.00	197.50	
TOTAL DEPRECIABLE INV.				790.00
OTHER INVESTMENT				
. LAND				0.
. INITIAL CAT.&CHEM.				23.00
. ROYALTY & FEES				0.
SUBTOTAL				23.00
WORKING CAPITAL				
. RAW MATERIALS				92.00
. ACCOUNTS RECEIVABLE				0.
. ACCOUNTS PAYABLE				0.
. NOBLE METALS				0.
. INT ON CONSTRUCTION	0.	0.	0.	
TOTAL CONST INTEREST				0.
SUBTOTAL				92.00
TOTAL INVESTMENT				905.00

ECONOMIC EVALUATION MODEL

JP8+DIESEL-15% ROI

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

PAGE 5 - 1

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR										
JET FUEL (BBLS)	14.56	29.11	29.11	29.11	29.11	29.11	29.11	29.11	29.11	29.11
AMMONIA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT										
JET FUEL $/BBL	58.85	58.85	58.85	58.85	58.85	58.85	58.85	58.85	58.85	58.85
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR										
JET FUEL	856.58	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16
AMMONIA	2.97	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	0.86	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

ECONOMIC EVALUATION MODEL

JP8+DIESEL-15% ROI

USAF SHALE OIL STUDY
PRODUCTION SUMMARY

RUN NUMBER 2
ALL $ VALUES IN MILLIONS

PAGE 5 - 2

YEAR	1995	1996	1997	1998	1999	2000
	100.00	100.00	100.00	100.00	100.00	100.00
PRODUCTION,MM UNITS/YEAR						
JET FUEL (BBLS)	29.11	29.11	29.11	29.11	29.11	29.11
AMMONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: $/UNIT						
JET FUEL $/BBL	58.85	58.85	58.85	58.85	58.85	58.85
AMMONIA $/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR $/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES $MM/YEAR						
JET FUEL	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16
AMMONIA	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	1.71	1.71	1.71	1.71	1.71	1.71

Appendix B.5

MAXIMUM JP-4 CASE -- STANDARD OPTIMIZATION REPORT

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PS1.0 16:04 NOV 20, 81 PAGE 2

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	QUANTITY LIMITS MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL $/DAY
	A	AV TURBINE FUEL JP-4				82583.75 BBL	56.8200	4692408.67
	A	SULFUR				87.79 TON	95.4500	8379.53
	A	ANHYDRUS AMMONIA				275.84 TON	155.0000	42754.63
	TOTAL SALES REVENUE							4743542.83

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER		14418.41 BBL	.0245	353.25
	50# STRIPPING STEAM		159.45 TON	.0000	.00
TOTAL RAW MATERIAL COST					3600353.25
GROSS MARGIN					1143189.58

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0 16:04 NOV 20, 81 PAGE 3

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	OPERATING COST $/BBL	OPERATING COST $/TON	OPERATING COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84601.3	12408.39	.687944	4.69045	58200.93
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	24850.2	2843.75	.052302	.45704	1299.71
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	17915.8	1946.07	.065593	.60385	1175.14
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1335.36		.56680	756.88
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.22		19.67483	1932.48
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		737.30		39.50067	29123.72
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17534.2	3069.99	.207814	1.18693	3643.86
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.22		17.81405	1749.71
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.84		2.68881	741.67
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13824.2	2027.59	.076524	.52174	1057.88
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57

TOTAL PROCESS UNIT OPERATING COST 159772.79

UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D
	BOILER WATER	MLBS	4839.81	.50000	2419.91

TOTAL UTILITY PURCHASES 2419.91

UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D	SOURCE	$/D
	600# STEAM	MLBS	4564.99	REFINERY FUELS	3112.49

TOTAL UTILITY PRODUCTION COSTS 3112.49

TOTAL OPERATING COST 165305.19

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	CAPITAL COST $/BBL	CAPITAL COST $/TON	CAPITAL COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84601.3	12408.39	1.910045	13.02282	161592.23
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	24850.2	2843.75	.090110	.78742	2239.24
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	17915.8	1946.07	.218830	2.01459	3920.52
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1335.36		1.18287	1579.56
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.22		57.37486	5635.41
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		737.30		162.24240	119620.79
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17534.2	3069.99	.530932	3.03242	9309.49
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.22		26.64155	2616.75
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.84		1.50765	415.86
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13824.2	2027.59	.211972	1.44524	2930.36
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10371.11
TOTAL							478315.80

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

MATERIAL BALANCE SUMMARY

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	86.192	14441.92	84.328	
COLD TREATED WATER	1.00000	14418.4	13.808	2524.45	14.741	
50# STRIPPING STEAM				159.45	.931	
TOTAL CHARGE		104418.4	100.000	17125.81	100.000	
PRODUCTS	**SP.GR.**	**BBL/D**	**LV%**	**TONS/D**	**WT%**	**MSCFD**
AV TURBINE FUEL JP-4	.78135	82583.8	79.089	11297.75	65.969	
SULFUR				87.79	.513	
ANHYDRUS AMMONIA				275.84	1.611	
TOTAL PRODUCTS SOLD		82583.8	79.089	11661.37	68.092	
STREAMS CONVERTED TO UTILITIES	**SP.GR.**	**BBL/D**	**LV%**	**TONS/D**	**WT%**	**MSCFD**
F.O. STAB BOTTOMS	.86400	13159.9	12.603	1990.75	11.624	
TOTAL STREAMS CONVERTED		13159.9	12.603	1990.75	11.624	
STREAMS NOT UTILIZED	**SP.GR.**	**BBL/D**	**LV%**	**TONS/D**	**WT%**	**MSCFD**
LOSS				27.02	.158	
SULFUR PLANT LOSS				10.43	.061	
CO2--HYD.PLT.				647.65	3.782	
TREATED SOUR WATER	1.00000	15927.1	15.253	2788.60	16.283	
TOTAL NOT UTILIZED		15927.1	15.253	3473.69	20.283	
TOTAL PRODUCTS MADE		111670.7	106.945	17125.81	100.000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY	CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY	BBLS/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY	BBLS/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY	BBLS/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY	BBLS/CD				84600.6	84600.6	168517609
NAPHTHA SPLITTER	CAPACITY	BBLS/CD				24851.3	24851.3	2335209
DEBUTANIZER	CAPACITY	BBLS/CD				17916.8	17916.8	4088542
FUEL GAS TREATER	CAPACITY	TONS/CD				1335.4	1335.4	1647258
SULFUR PLANT	CAPACITY	TONS/CD				98.2	98.2	5876921
HYDROGEN PLANT	CAPACITY	TONS/CD				737.3	737.3	124747396
SOUR WATER TREATING	CAPACITY	BBLS/CD				17624.7	17624.7	9708468
AMINE REGENERATION	CAPACITY	TONS/CD				98.2	98.2	2728900
AMMONIA PLANT	CAPACITY	TONS/CD				275.8	275.8	433687
FUEL OIL STABILIZER	CAPACITY	BBLS/CD				13824.1	13824.1	3055945
COMBINED FACILITIES	CAPACITY	BBLS/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT								498804934

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	SPGR@60F	WT% SULF	VL% AROM	SMOKE PT	FREEZ PT	D+L 293F	D+L 374F	D+L 473F
HC KEROSINE:300-520F	65556.5	9207.64	.8022	.0003	9.0000	27.0000	-58.0000	2.5000	38.0000	88.0000
SPLITTER BOTTOMS	6390.3	852.56	.7620	.0003	7.0000	35.0000	-120.0000	98.0000	110.0000	100.0000
LT NAPHTHA JP-4	10637.0	1237.55	.6645	.0003	2.0000	35.0000	-160.0000	120.0000	120.0000	110.0000
BLEND	82583.8	11297.75	.7814	.0003	7.9400	28.6000	-75.9353	25.0240	54.1331	91.7622
SPECIFICATIONS		MAX	.8017	.4000	25.0000		-72.0000			
		MIN	.7507			20.0000		20.0000	50.0000	90.0000

PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	D+L 518F
HC KEROSINE:300-520F	65556.5	9207.64	100.0000
SPLITTER BOTTOMS	6390.3	852.56	100.0000
LT NAPHTHA JP-4	10637.0	1237.55	100.0000
BLEND	82583.8	11297.75	100.0000
SPECIFICATIONS		MAX	100.0000
		MIN	

PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR@60F
SULFUR		87.79	
BLEND		87.79	
NO SPECIFICATIONS			

PRODUCT BLENDING

ANHYDRUS AMMONIA	BBL/D	TONS/D	SPGR@60F
ANHYDRUS AMMONIA		275.84	
BLEND		275.84	
NO SPECIFICATIONS			

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR@60F
F.O. STAB BOTTOMS	13159.9	1990.75	.8640
BLEND	13159.9	1990.75	.8640

NO SPECIFICATIONS

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE
FEED PREPARATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE
L.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.HT	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.18
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE
H.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.HT	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(HP)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE
HYDROCRACKING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	84601.3	97.18	12408.39	93.47	
HYDROGEN (97%)				277.45	2.09	86409.58
COLD TREATED WATER	1.0000	2454.2	2.82	429.70	3.24	
50# STRIPPING STEAM				159.45	1.20	
CHARGE		87055.5	100.00	13274.99	100.00	
PRODUCTS						
LP FLASH GAS(JP-4)				613.10	4.62	29028.66
PROD FRACT OV'D:JP-4	.6536	24850.2	28.55	2843.75	21.42	
SOUR WATER (HC)	1.0000	3440.8	3.95	602.43	4.54	
HC KEROSINE:300-520F	.8022	65556.5	75.30	9207.64	69.36	
LOSS				8.07	.06	
PRODUCTS		93847.5	107.80	13274.99	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA SPLITTER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
PROD FRACT OV'D:JP-4	.6536	24850.2	100.00	2843.75	100.00	
CHARGE		24850.2	100.00	2843.75	100.00	
PRODUCTS						
SPLITTER GAS:JP-4				45.13	1.59	918.37
SPLIT OV LIQ:JP-4	.6204	17915.8	72.10	1946.07	68.43	
SPLITTER BOTTOMS	.7620	6390.3	25.72	852.56	29.98	
PRODUCTS		24306.1	97.81	2843.75	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE
DEBUTANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLIT OV LIQ:JP-4	.6204	17915.8	100.00	1946.07	100.00	
CHARGE		17915.8	100.00	1946.07	100.00	
PRODUCTS						
DEBUT OVER'D=JP-4	.5464	6693.0	37.36	640.29	32.90	9451.01
LT NAPHTHA JP-4	.6645	11223.3	62.64	1305.77	67.10	
PRODUCTS		17916.3	100.00	1946.07	100.00	

DETAILED MATERIAL BALANCE
FUEL GAS TREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
LP FLASH GAS(JP-4)				613.10	45.91	29028.66
DEBUT OVER'D=JP-4	.5464	6693.0	100.00	640.29	47.95	9451.01
SPLITTER GAS:JP-4				45.13	3.38	915.37
F.O. STAB OVER'D				36.84	2.76	2018.90
CHARGE		6693.0	100.00	1335.36	100.00	
PRODUCTS						
HYDROGEN SULFIDE				18.65	1.40	415.25
TRT LP FLASH:JP-4				603.04	45.16	28804.15
TRT DEB OV'D=JP-4				635.17	47.57	9337.27
TRT SPLIT GAS=JP-4				44.28	3.32	896.15
TRT F.O. STAB OV'D				34.23	2.56	1960.49
PRODUCTS				1335.36	100.00	

DETAILED MATERIAL BALANCE
SULFUR PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.22	100.00	2187.43
CHARGE				98.22	100.00	
PRODUCTS						
SULFUR				87.79	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.22	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE
HYDROGEN PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT LP FLASH:JP-4				603.04	43.54	28804.15
TRT DEB OV'D=JP-4				635.17	45.86	9337.27
TRT SPLIT GAS=JP-4				44.28	3.20	896.15
TRT F.O. STAB OV'D				34.23	2.47	1960.49
LT NAPHTHA JP-4	.6645	586.4	100.00	68.22	4.93	
CHARGE		586.4	100.00	1384.94	100.00	
PRODUCTS						
HYDROGEN (97%)				737.30	53.24	229623.91
CO2--HYD.PLT.				647.65	46.76	
PRODUCTS				1384.94	100.00	

DETAILED MATERIAL BALANCE
SOUR WATER TREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SOUR WATER - L.P.HT	1.0000	3558.4	20.29	623.02	20.29	
SOUR WATER - H.P.HT	1.0000	10535.1	60.08	1844.54	60.08	
SOUR WATER (HC)	1.0000	3440.8	19.62	602.43	19.62	
CHARGE		17534.2	100.00	3069.99	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15843.6	90.36	2773.98	90.36	
AMMONIA				290.46	9.46	
LOSS				5.55	.18	
PRODUCTS		15843.6	90.36	3069.99	100.00	

DETAILED MATERIAL BALANCE
AMINE REGENERATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.22	100.00	2187.43
CHARGE				98.22	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.22	100.00	2187.43
PRODUCTS				98.22	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE
AMMONIA PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
AMMONIA				290.46	100.00	
CHARGE				290.46	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.5		14.62	5.03	
ANHYDRUS AMMONIA				275.84	94.97	
PRODUCTS		83.5		290.46	100.00	

DETAILED MATERIAL BALANCE
FUEL OIL STABILIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	13824.2	100.00	2027.59	100.00	
CHARGE		13824.2	100.00	2027.59	100.00	
PRODUCTS						
F.O. STAB OVER'D				36.84	1.82	2018.90
F.O. STAB BOTTOMS	.8640	13159.9	95.19	1990.75	98.18	
PRODUCTS		13159.9	95.19	2027.59	100.00	

DETAILED MATERIAL BALANCE
COMBINED FACILITIES
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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USAF SHALE OIL TO FUELS
Phase IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
ELECTRIC POWER   UNIT IS KWH   PRICE IS .04500/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	7.0969	48.387	600404.58	27018.21
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.3911	3.418	9719.95	437.40
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	.1399	1.288	2506.53	112.79
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		21.974	2158.30	97.12
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		235.698	173779.45	7820.08
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.3787	2.163	6640.41	298.82
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		40.773	4004.76	180.21
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84		3.393	935.86	42.11
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.1638	1.116	2263.80	101.87
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							1101184.93	49553.32

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
600# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.0075	.051	636.55	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		.220	21.58	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		-5.197	-3831.71	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							21.50	
AMOUNT PRODUCED FROM REFINERY FUELS							4564.99	3112.49
AMOUNT CONVERTED TO 150# STEAM							4033.71	
AMOUNT CONVERTED TO 50# STEAM							509.78	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.0398	.271	3365.15	100.95
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.0299	.261	742.22	22.27
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	.0116	.106	207.26	6.22
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		93.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		.829	611.33	18.34
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.1336	.763	2342.76	70.28
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		32.389	3181.27	95.44
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84		10.961	3023.44	90.70
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.0200	.137	277.17	8.32
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							13896.47	416.89

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
REFINERY FUELS UNIT IS MMBTU
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.1729	1.179	14625.76	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.0640	.559	1591.08	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		57.519	42408.30	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.0486	.331	672.15	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							65725.22	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							69878.21	
AMOUNT CONVERTED TO 600# STEAM							4149.99	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
150# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		-7.593	-745.80	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.2633	1.504	4616.45	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		1.660	163.07	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							4033.71	
AMOUNT PRODUCED FROM 600# STEAM							4033.71	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
50# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	-.0031	-.021	-261.82	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	.0460	.424	824.35	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		-9.864	-968.82	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		9.327	916.07	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							509.78	
AMOUNT PRODUCED FROM 600# STEAM							509.78	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
BOILER WATER   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12406.39	.0112	.076	946.76	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24650.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		[illegible]3.22		18.946	1860.89	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		16.887	12450.88	
SOUR WATER TREATI'G	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATI..	COMBINED MODES	COMPOSITE USAGE		98.22				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							15258.54	
AMOUNT PURCHASED							4839.81	2419.91
AMOUNT PRODUCED FROM CONDENSATE							10418.72	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
CONDENSATE UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	-.0193	-.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-.0158	-.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	-.0075	-.051	-636.55	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	-.0460	-.424	-824.35	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		-.684	-67.14	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	-.2633	-1.504	-4616.45	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		-10.987	-1079.15	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-10418.72	
AMOUNT CONVERTED TO BOILER WATER							10418.72	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
CAT. & CHEMICALS UNIT IS $ PRICE IS 1.00000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.0731	.498	6180.62	6180.62
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		5.004	3689.72	3689.72
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		.283	27.76	27.76
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							24064.75	24064.75

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STE AM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STE AM MLBS	50# STEA M MLBS	BOILER W ATER MLBS	CONDENSA TE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	600404.6	636.6	3365.2	14625.8		-261.8	966.8	-636.6
NAPHTHA SPLITTER	9720.0		742.2	1591.1				
DEBUTANIZER	2506.5		207.3			824.4		-824.4
SULFUR PLANT	2158.3	21.6			-745.8	-968.8	1860.9	-67.1
HYDROGEN PLANT	173779.5	-3831.7	611.3	42408.3			12450.9	
SOUR WATER TREATING	6640.4		2342.8		4616.4			-4616.4
AMINE REGENERATION	4004.8		3181.3		163.1	916.1		-1079.2
AMMONIA PLANT	935.9		3023.4					
FUEL OIL STABILIZER	2263.8		277.2	672.1				
TOTAL CONSUMPTION	1101184.9	21.5	13896.5	65725.2	4033.7	509.8	15258.5	-10418.7

USAF SHALE OIL TO FUELS
PHASE IV
CASE 1 - MAXIMUM JP-4 JET FUEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & CHEMICALS $
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	6180.6
NAPHTHA SPLITTER	
DEBUTANIZER	
SULFUR PLANT	
HYDROGEN PLANT	3689.7
SOUR WATER TREATING	
AMINE REGENERATION	27.8
AMMONIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	24064.7

Appendix B.6

JP-4 PLUS DIESEL CASE -- STANDARD OPTIMIZATION REPORT

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	QUANTITY LIMITS MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL $/DAY
	A	AV TURBINE FUEL JP-4				48559.86 BBL	58.8200	2856290.96
	A	DF-2/DF-M DIESEL				33184.22 BBL	58.8200	1951895.82
	A	SULFUR				87.76 TON	95.4500	8376.31
	A	ANHYDRUS AMMONIA				275.43 TON	155.0000	42691.06
TOTAL SALES REVENUE								4859254.15

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER		14342.57 BBL	.0245	351.39
	50# STRIPPING STEAM		154.52 TON	.0000	.00
TOTAL RAW MATERIAL COST					3600351.39
GROSS MARGIN					1258902.76

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	TON/D	OPERATING COST $/BBL	$/TON	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	81987.1	12024.97	.618072	4.21406	50673.94
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11443.6	1292.32	.083930	.74321	960.46
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8380.3	901.49	.113850	1.05835	954.09
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		778.09		.91020	708.21
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		19.67483	1931.73
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		421.42		43.68431	18409.54
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17427.9	3051.37	.208795	1.19253	3638.86
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		17.81405	1749.04
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.43		2.68881	740.57
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	16438.4	2411.00	.067122	.45764	1103.38
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE COST		285.42		162.49114	46377.54
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57
TOTAL PROCESS UNIT OPERATING COST							187338.18

UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D	
	BOILER WATER	MLBS	6310.09	.50000	3155.05	
TOTAL UTILITY PURCHASES						3155.05

UTILITY SALES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D	
	600# STEAM	MLBS	422.80	.00010	.04	
	50# STEAM	MLBS	623.15	.00010	.06	
TOTAL UTILITY SALES						.10

TOTAL OPERATING COST 190493.12

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	CAPITAL COST $/BBL	CAPITAL COST $/TON	CAPITAL COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	81987.1	12024.97	1.926602	13.13572	157956.60
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11443.6	1292.32	.132790	1.17586	1519.60
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8380.3	901.49	.319962	2.97439	2681.37
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		778.09		1.54961	1205.73
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		57.38256	5633.99
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		421.42		178.92713	75403.88
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17427.9	3051.37	.532233	3.03985	9275.71
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		26.64666	2616.25
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.43		1.50877	415.56
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	16438.4	2411.00	.194388	1.32535	3195.43
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE COST		285.42		383.49301	109454.97
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10371.11
TOTAL							537814.67

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

MATERIAL BALANCE SUMMARY

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	86.254	14441.92	84.418	
COLD TREATED WATER	1.00000	14342.6	13.746	2511.17	14.679	
50# STRIPPING STEAM				154.52	.903	
TOTAL CHARGE		104342.6	100.000	17107.61	100.000	

PRODUCTS	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
AV TURBINE FUEL JP-4	.78543	48559.9	46.539	6677.79	39.034	
DF-2/DF-M DIESEL	.83290	33184.2	31.803	4839.21	28.287	
SULFUR				87.76	.513	
ANHYDRUS AMMONIA				275.43	1.610	
TOTAL PRODUCTS SOLD		81744.1	78.342	11880.18	69.444	

STREAMS CONVERTED TO UTILITIES	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	9433.5	9.041	1427.04	8.342	
TOTAL STREAMS CONVERTED		9433.5	9.041	1427.04	8.342	

STREAMS NOT UTILIZED	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LOSS				26.76	.156	
SULFUR PLANT LOSS				10.43	.061	
CO2--HYD.PLT.				338.05	1.976	
TREATED SOUR WATER	1.00000	15823.2	15.165	2770.40	16.194	
PARTIAL OXIDAT.-LOSS				654.74	3.827	
TOTAL NOT UTILIZED		15823.2	15.165	3800.39	22.215	
TOTAL PRODUCTS MADE		107000.7	102.548	17107.61	100.000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY	CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY	BBLS/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY	BBLS/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY	BBLS/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY	BBLS/CD				81986.5	81986.5	164726166
NAPHTHA SPLITTER	CAPACITY	BBLS/CD				11444.7	11444.7	1584723
DEBUTANIZER	CAPACITY	BBLS/CD				8380.8	8380.8	2796286
FUEL GAS TREATER	CAPACITY	TONS/CD				778.1	778.1	1257405
SULFUR PLANT	CAPACITY	TONS/CD				98.2	98.2	5875452
HYDROGEN PLANT	CAPACITY	TONS/CD				421.4	421.4	78635478
SOUR WATER TREATING	CAPACITY	BBLS/CD				17518.3	17518.3	9673242
AMINE REGENERATION	CAPACITY	TONS/CD				98.2	98.2	2728375
AMMONIA PLANT	CAPACITY	TONS/CD				275.4	275.4	433365
FUEL OIL STABILIZER	CAPACITY	BBLS/CD				16438.2	16438.2	3332381
PARTIAL OXIDATION	CAPACITY	TONS/CD				285.4	285.4	114145893
COMBINED FACILITIES	CAPACITY	BBLS/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT								560853766

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

PRODUCT BLENDING

AV TURBINE FUEL JP-4		BBL/D	TONS/D	SPGR@60F	WT% SULF	VL% AROM	SMOKE PT	FREEZ PT	D+L 293F	D+L 374F	D+L 473F
HC KEROSINE:300-520F		40776.0	5727.13	.8022	.0003	9.0000	27.0000	-58.0000	2.5000	38.0000	88.0000
SPLITTER BOTTOMS		2742.7	365.92	.7620	.0003	7.0000	35.0000	-120.0000	98.0000	110.0000	100.0000
LT NAPHTHA JP-4 DM		5041.1	584.74	.6625	.0003	2.0000	35.0000	-160.0000	120.0000	120.0000	110.0000
BLEND		48559.9	6677.79	.7854	.0003	8.1600	28.2800	-72.0907	20.0919	50.5793	90.9617
SPECIFICATIONS	MAX			.8017	.4000	25.0000		-72.0000			
	MIN			.7507			20.0000		20.0000	50.0000	90.0000

PRODUCT BLENDING

AV TURBINE FUEL JP-4		BBL/D	TONS/D	D+L 518F
HC KEROSINE:300-520F		40776.0	5727.13	100.0000
SPLITTER BOTTOMS		2742.7	365.92	100.0000
LT NAPHTHA JP-4 DM		5041.1	584.74	100.0000
BLEND		48559.9	6677.79	100.0000
SPECIFICATIONS	MAX			100.0000
	MIN			

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USAF SHALE CIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	SPGR@60F	WT% SULF	FLASH PT	CETANE I	D+L 700F	VIS 100F	POUR PT.	CLOUD PT
HC DIESEL:520-700F	33184.2	4839.21	.8329	.0003	268.0000	56.0000	100.0000	18.2400	.0000	5.0000
BLEND	33184.2	4839.21	.8329	.0003	268.0000	56.0000	100.0000	18.2400	.0000	5.0000
SPECIFICATIONS		MAX	.8607	.7000			100.0000	18.4100	.0000	5.0000
		MIN	.8203		133.0000	45.0000		10.3100		

PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	D+L 675F	D+L 725F
HC DIESEL:520-700F	33184.2	4839.21	90.0000	100.0000
BLEND	33184.2	4839.21	90.0000	100.0000
SPECIFICATIONS		MAX		100.0000
		MIN	90.0000	

PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR@60F
SULFUR		87.76	
BLEND		87.76	
NO SPECIFICATIONS			

PRODUCT BLENDING

ANHYDRUS AMMONIA	BBL/D	TONS/D	SPGR@60F
ANHYDRUS AMMONIA		275.43	
BLEND		275.43	
NO SPECIFICATIONS			

BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR@60F
F.O. STAB BOTTOMS	9433.5	1427.04	.8640
BLEND	9433.5	1427.04	.8640
NO SPECIFICATIONS			

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
FEED PREPARATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE
L.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.HT	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.18
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE
H.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.HT	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(HP)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
HYDROCRACKING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	81987.1	97.18	12024.97	93.63	
HYDROGEN (97%)				246.99	1.92	76923.54
COLD TREATED WATER	1.0000	2378.4	2.82	416.42	3.24	
50# STRIPPING STEAM				154.52	1.20	
CHARGE		84365.5	100.00	12842.91	100.00	
PRODUCTS						
LP FLASH GAS:JP-4-DM				392.62	3.06	24226.60
PROD FRACT OV:JP4-DM	.6450	11443.6	13.56	1292.32	10.06	
SOUR WATER (HC)	1.0000	3334.4	3.95	583.81	4.55	
HC KEROSINE:300-520F	.8022	40776.0	48.33	5727.13	44.59	
HC DIESEL:520-700F	.8329	33184.2	39.33	4839.21	37.68	
LOSS				7.82	.06	
PRODUCTS		88738.3	105.18	12842.91	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA SPLITTER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
PROD FRACT OV:JP4-DM	.6450	11443.6	100.00	1292.32	100.00	
CHARGE		11443.6	100.00	1292.32	100.00	
PRODUCTS						
SPLITTER GAS=JP4-DM				24.92	1.93	580.80
SPLIT OV LIQ=JP4-DM	.6144	8380.3	73.23	901.49	69.76	
SPLITTER BOTTOMS	.7620	2742.7	23.97	365.92	28.31	
PRODUCTS		11123.0	97.20	1292.32	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
DEBUTANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLIT OV LIQ=JP4-DM	.6144	8380.3	100.00	901.49	100.00	
CHARGE		8380.3	100.00	901.49	100.00	
PRODUCTS						
DEBUT OVER'D=JP4-DM	.5418	3339.0	39.84	316.75	35.14	4802.32
LT NAPHTHA JP-4 DM	.6625	5041.1	60.15	584.74	64.86	
PRODUCTS		8380.2	100.00	901.49	100.00	

DETAILED MATERIAL BALANCE
FUEL GAS TREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
LP FLASH GAS:JP-4-DM				392.62	50.46	24226.60
DEBUT OVER'D=JP4-DM	.5418	3339.0	100.00	316.75	40.71	4802.32
SPLITTER GAS=JP4-DM				24.92	3.20	580.80
F.O. STAB OVER'D				43.81	5.63	2400.68
CHARGE		3339.0	100.00	778.09	100.00	
PRODUCTS						
HYDROGEN SULFIDE				18.61	2.39	414.41
TRT LP FLASH:JP4-DM				382.92	49.21	23998.91
TRT DEB OV'D=JP4-DM				311.77	40.07	4691.31
TRT SPLIT GAS=JP4-DM				24.09	3.10	562.38
TRT F.O. STAB OV'D				40.70	5.23	2331.22
PRODUCTS				778.09	100.00	

DETAILED MATERIAL BALANCE
SULFUR PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.18	100.00	2186.59
CHARGE				98.18	100.00	
PRODUCTS						
SULFUR				87.76	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.18	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
HYDROGEN PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT LP FLASH:JP4-DM				382.92	50.42	23998.91
TRT DEB OV'D=JP4-DM				311.77	41.05	4691.31
TRT SPLIT GAS=JP4-DM				24.09	3.17	562.38
TRT F.O. STAB OV'D				40.70	5.36	2331.22
CHARGE				759.48	100.00	
PRODUCTS						
HYDROGEN (97%)				421.42	55.49	131247.89
CO2--HYD.PLT.				338.05	44.51	
PRODUCTS				759.48	100.00	

DETAILED MATERIAL BALANCE
SOUR WATER TREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SOUR WATER - L.P.HT	1.0000	3558.4	20.42	623.02	20.42	
SOUR WATER - H.P.HT	1.0000	10535.1	60.45	1844.54	60.45	
SOUR WATER (HC)	1.0000	3334.4	19.13	583.81	19.13	
CHARGE		17427.9	100.00	3051.37	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15739.8	90.31	2755.81	90.31	
AMMONIA				290.02	9.50	
LOSS				5.54	.18	
PRODUCTS		15739.8	90.31	3051.37	100.00	

DETAILED MATERIAL BALANCE
AMINE REGENERATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.18	100.00	2186.59
CHARGE				98.18	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.18	100.00	2186.59
PRODUCTS				98.18	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIE

DETAILED MATERIAL BALANCE
AMMONIA PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
AMMONIA				290.02	100.00	
CHARGE				290.02	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.4		14.60	5.03	
ANHYDRUS AMMONIA				275.43	94.97	
PRODUCTS		83.4		290.02	100.00	

DETAILED MATERIAL BALANCE
FUEL OIL STABILIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	16438.4	100.00	2411.00	100.00	
CHARGE		16438.4	100.00	2411.00	100.00	
PRODUCTS						
F.O. STAB OVER'D				43.81	1.82	2400.68
F.O. STAB BOTTOMS	.8640	15648.4	95.19	2367.20	98.18	
PRODUCTS		15648.4	95.19	2411.00	100.00	

DETAILED MATERIAL BALANCE
PARTIAL OXIDATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
F.O. STAB BOTTOMS	.8640	6215.0	100.00	940.16	100.00	
CHARGE		6215.0	100.00	940.16	100.00	
PRODUCTS						
HYDROGEN (97%)				285.42	30.36	88889.98
PARTIAL OXIDAT.-LOSS				654.74	69.64	
PRODUCTS				940.16	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
COMBINED FACILITIES
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
ELECTRIC POWER UNIT IS KWH PRICE IS .04500/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	6.1047	41.622	500503.29	22522.65
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.3912	3.464	4476.35	201.44
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.1399	1.301	1172.47	52.76
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		21.974	2157.47	97.09
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		238.910	100682.00	4530.69
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	.3787	2.163	6600.30	297.01
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		40.773	4003.22	180.14
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43		3.393	934.47	42.05
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00	.1638	1.116	2691.89	121.13
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		2072.400	591495.71	26617.31
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							1513488.45	68106.98

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
600# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		.220	21.57	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		-4.995	-2105.17	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		-14.086	-4020.37	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-2908.89	
AMOUNT SOLD							422.80	.04
AMOUNT CONVERTED TO 150# STEAM							2486.10	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0263	.179	2152.47	64.57
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.0299	.264	341.82	10.25
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.0116	.107	96.91	2.91
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		.869	366.13	10.98
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	.1336	.763	2328.61	69.86
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		32.389	3180.05	95.40
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43		10.961	3018.95	90.57
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00	.0200	.137	329.58	9.89
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		98.338	28067.22	842.02
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							40027.60	1200.83

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
REFINERY FUELS   UNIT IS MMBTU
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.1721	1.173	14110.10	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.0640	.567	732.75	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		56.904	23980.61	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00	.0486	.331	799.25	
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		14.149	4038.35	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							50088.99	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							50088.99	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
150# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	-.0185	-.126	-1519.96	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-7.593	-745.51	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	.2633	1.504	4588.56	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		1.660	163.00	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							2486.10	
AMOUNT PRODUCED FROM 600# STEAM							2486.10	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
50# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	-.0117	-.079	-955.99	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.0460	.428	385.57	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-9.864	-968.45	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		9.327	915.71	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-623.15	
AMOUNT SOLD							623.15	.06

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
BOILER WATER   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0390	.266	3201.05	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		18.946	1860.18	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		16.550	6974.54	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		12.576	3589.39	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							15625.15	
AMOUNT PURCHASED							6310.09	3155.05
AMOUNT PRODUCED FROM CONDENSATE							9315.06	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
CONDENSATE UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	-.0193	-.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-.0158	-.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	-.0460	-.428	-385.57	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-.684	-67.12	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	-.2633	-1.504	-4588.56	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		-10.987	-1078.74	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-9315.06	
AMOUNT CONVERTED TO BOILER WATER							9315.06	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
CAT. & CHEMICALS UNIT IS $ PRICE IS 1.00000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0578	.394	4742.65	4742.65
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		4.979	2098.39	2098.39
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		.283	27.75	27.75
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		4.223	1205.31	1205.31
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							22240.75	22240.75

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STEAM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STEAM MLBS	50# STEAM MLBS	BOILER WATER MLBS	CONDENSATE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	500503.3		2152.5	14110.1	-1520.0	-956.0	3201.0	
NAPHTHA SPLITTER	4476.4		341.8	732.7				
DEBUTANIZER	1172.5		96.9			385.6		-385.6
SULFUR PLANT	2157.5	21.6			-745.5	-968.4	1860.2	-67.1
HYDROGEN PLANT	100682.0	-2105.2	366.1	23980.6			6974.5	
SOUR WATER TREATING	6600.3		2328.6		4588.6			-4588.6
AMINE REGENERATION	4003.2		3180.1		163.0	915.7		-1078.7
AMMONIA PLANT	934.5		3018.9					
FUEL OIL STABILIZER	2691.9		329.6	799.2				
PARTIAL OXIDATION	591495.7	-4020.4	28067.2	4038.3			3589.4	
TOTAL CONSUMPTION	1513488.5	-2908.9	40027.6	50089.0	2486.1	-623.2	15625.2	-9315.1

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & CHEMICALS $
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	4742.6
NAPHTHA SPLITTER	
DEBUTANIZER	
SULFUR PLANT	
HYDROGEN PLANT	2098.4
SOUR WATER TREATING	
AMINE REGENERATION	27.7
AMMONIA PLANT	
FUEL OIL STABILIZER	
PARTIAL OXIDATION	1205.3
TOTAL CONSUMPTION	22240.7

Appendix B.7

MAXIMUM JP-8 CASE -- STANDARD OPTIMIZATION REPORT

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	QUANTITY LIMITS MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL $/DAY
	A	UNLEADED GASOLINE				7963.79 BBL	58.8000	468270.85
	A	AV TURBINE FUEL JP-8				72667.97 BBL	58.8000	4272876.64
	A	SULFUR				87.77 TON	95.4500	8377.85
	A	ANHYDRUS AMMONIA				276.68 TON	155.0000	42885.11
	TOTAL SALES REVENUE							4792410.45

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER		14749.31 BBL	.0245	361.36
	50# STRIPPING STEAM		169.56 TON	.0000	.00
TOTAL RAW MATERIAL COST					3600361.36
GROSS MARGIN					1192049.09

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	OPERATING COST $/BBL	OPERATING COST $/TON	OPERATING COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	89966.8	13195.34	.677281	4.61775	60932.81
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	22993.1	2626.40	.054444	.47664	1251.84
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	16633.9	1804.78	.068802	.63412	1144.45
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	1229.3	117.47	.532947	5.57700	655.14
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1176.39		.61770	726.66
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.20		19.67483	1932.09
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		752.27		39.28601	29553.74
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	5837.5	778.81	.295563	2.21537	1725.34
UOP PLATFORMING	COMBINED MODES	COMPOSITE COST	5837.6	778.42	.750106	5.62530	4378.83
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17927.7	3138.88	.204485	1.16792	3665.95
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.20		17.81405	1749.36
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		276.68		2.68881	743.93
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	8458.7	1240.63	.115919	.79034	980.52
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57
DUMMY UNIT	COMBINED MODES	COMPOSITE COST	840.6	84.52			

TOTAL PROCESS UNIT OPERATING COST 169531.48

UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D
	BOILER WATER	MLBS	5560.86	.50000	2780.43

TOTAL UTILITY PURCHASES 2780.43

UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D	SOURCE	$/D
	600# STEAM	MLBS	4151.38	REFINERY FUELS	2830.48

TOTAL UTILITY PRODUCTION COSTS 2830.48

TOTAL OPERATING COST 175142.40

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	CAPITAL COST $/BBL	CAPITAL COST $/TON	CAPITAL COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	89966.8	13195.34	1.878017	12.80446	168959.22
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	22993.1	2626.40	.093678	.82011	2153.93
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	16633.9	1804.78	.227102	2.09310	3777.60
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	1229.3	117.47	.744536	7.79117	915.24
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1176.39		1.26026	1482.56
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.20		57.37868	5634.67
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		752.27		161.67252	121621.61
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	5837.5	778.81	.560212	4.19902	3270.22
UOP PLATFORMING	COMBINED MODES	COMPOSITE COST	5837.6	778.42	1.772736	13.29436	10348.56
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17927.7	3138.88	.526209	3.00544	9433.73
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.20		26.64422	2616.49
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		276.68		1.50535	416.50
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	8458.7	1240.63	.270987	1.84761	2292.20
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10371.11
DUMMY UNIT	COMBINED MODES	COMPOSITE COST	840.6	84.52			
TOTAL							501378.11

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

MATERIAL BALANCE SUMMARY

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	85.919	14441.92	83.995	
COLD TREATED WATER	1.00000	14749.3	14.081	2582.39	15.019	
50# STRIPPING STEAM				169.56	.986	
TOTAL CHARGE		104749.3	100.000	17193.86	100.000	

PRODUCTS	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
UNLEADED GASOLINE	.74714	7963.8	7.603	1041.78	6.059	
AV TURBINE FUEL JP-8	.80500	72668.0	69.373	10242.09	59.568	
SULFUR				87.77	.510	
ANHYDRUS AMMONIA				276.68	1.609	
TOTAL PRODUCTS SOLD		80631.8	76.976	11648.32	67.747	

STREAMS CONVERTED TO UTILITIES	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	8052.2	7.687	1218.09	7.084	
LT NAPHTHA JP-8	.66430	6918.6	6.605	804.69	4.680	
TOTAL STREAMS CONVERTED		14970.8	14.292	2022.78	11.765	

STREAMS NOT UTILIZED	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LOSS				27.54	.160	
SULFUR PLANT LOSS				10.43	.061	
CO2--HYD.PLT.				628.16	3.653	
TREATED SOUR WATER	1.00000	16315.7	15.576	2856.63	16.614	
TOTAL NOT UTILIZED		16315.7	15.576	3522.76	20.488	
TOTAL PRODUCTS MADE		111918.2	106.844	17193.86	100.000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY CATEGORY		MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY	BBLS/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY	BBLS/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY	BBLS/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY	BBLS/CD				89966.1	89966.1	176200324
NAPHTHA SPLITTER	CAPACITY	BBLS/CD				22993.9	22993.9	2246246
DEBUTANIZER	CAPACITY	BBLS/CD				16634.3	16634.3	3939493
DEPROPANIZER	CAPACITY	BBLS/CD				1229.2	1229.2	954469
FUEL GAS TREATER	CAPACITY	TONS/CD				1176.4	1176.4	1546099
SULFUR PLANT	CAPACITY	TONS/CD				98.2	98.2	5876153
HYDROGEN PLANT	CAPACITY	TONS/CD				752.3	752.3	126833967
NAPHTHA HYDROTREATER	CAPACITY	BBLS/CD				5837.5	5837.5	3410374
UOP PLATFORMING	CAPACITY	BBLS/CD				5837.8	5837.8	10792066
SOUR WATER TREATING	CAPACITY	BBLS/CD				18018.5	18018.5	9838031
AMINE REGENERATION	CAPACITY	TONS/CD				98.2	98.2	2728626
AMMONIA PLANT	CAPACITY	TONS/CD				276.7	276.7	434349
FUEL OIL STABILIZER	CAPACITY	BBLS/CD				8458.6	8458.6	2390435
COMBINED FACILITIES	CAPACITY	BBLS/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT								522855633

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

PRODUCT BLENDING

UNLEADED GASOLINE		BBL/D	TONS/D	SPGR@60F	WT% SULF	RES OCTN	MOT OCTN	(R+M)12	RVP INDX	VL% AROM	D+L 131F
LT NAPHTHA JP-8		2498.0	290.54	.6643	.0003	75.0000	73.0000	74.0000	175.0000	2.0000	51.0000
100 RON PLATFORMATE		4625.2	666.71	.8233	.0003	100.0000	88.6000	94.3000	55.1000	72.6000	1.0000
MIXED BUTANES		840.6	84.52	.5743	.0003	98.5000	94.3000	96.4000	1280.0000	.0000	100.0000
BLEND		7963.8	1041.78	.7471	.0003	92.0000	84.3084	88.1542	222.0000	42.7920	27.1330
SPECIFICATIONS	MAX				.1000				222.0000	55.0000	
	MIN					92.0000	82.0000	87.0000			10.0000

PRODUCT BLENDING

UNLEADED GASOLINE		BBL/D	TONS/D	D+L 171F	D+L 235F	D+L 365F	D+L 437F
LT NAPHTHA JP-8		2498.0	290.54	96.0000	100.0000	100.0000	100.0000
100 RON PLATFORMATE		4625.2	666.71	7.0000	38.0000	100.0000	100.0000
MIXED BUTANES		840.6	84.52	100.0000	100.0000	100.0000	100.0000
BLEND		7963.8	1041.78	44.7327	63.9916	100.0000	100.0000
SPECIFICATIONS	MAX			50.0000			100.0000
	MIN				50.0000	90.0000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	SPGR@60F	WT% SULF	VL% AROM	SMOKE PT	FREEZ PT	VL% NAPH	FLASH PT	D+L 401F
HC KEROSINE:300-550F	72668.0	10242.09	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
BLEND	72668.0	10242.09	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
SPECIFICATIONS		MAX	.8398	.4000	25.0000		-58.0000	3.0000		
		MIN	.7751			20.0000			100.0000	10.0000

PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	D+L 572F
HC KEROSINE:300-550F	72668.0	10242.09	100.0000
BLEND	72668.0	10242.09	100.0000
SPECIFICATIONS		MAX	100.0000
		MIN	

PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR@60F
SULFUR		87.77	
BLEND		87.77	
NO SPECIFICATIONS			

PRODUCT BLENDING

ANHYDRUS AMMONIA	BBL/D	TONS/D	SPGR@60F
ANHYDRUS AMMONIA		276.68	
BLEND		276.68	
NO SPECIFICATIONS			

RECYCLE STREAM BLENDING

MIXED BUTANES	BBL/D	TONS/D	SPGR@60F
MIXED C4'S:JP-8	840.6	84.52	.5743
BLEND	840.6	84.52	.5743
NO SPECIFICATIONS			

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR@60F
F.O. STAB BOTTOMS	8052.2	1218.09	.8640
LT NAPHTHA JP-8	6918.6	804.69	.6643
BLEND	14970.8	2022.78	.7717

NO SPECIFICATIONS

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
FEED PREPARATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE
L.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.HT	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.18
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE
H.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.HT	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(HP)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
HYDROCRACKING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	89966.8	97.18	13195.34	93.49	
HYDROGEN (97%)				291.88	2.07	90903.50
COLD TREATED WATER	1.0000	2609.9	2.82	456.95	3.24	
50# STRIPPING STEAM				169.56	1.20	
CHARGE		92576.7	100.00	14113.74	100.00	
PRODUCTS						
LP FLASH GAS:JP-8				596.03	4.22	29761.69
PROD FRACT OV:JP-8	.6524	22993.1	24.84	2626.40	18.61	
SOUR WATER (HC)	1.0000	3659.0	3.95	640.63	4.54	
HC KEROSINE:300-550F	.8050	72668.0	78.49	10242.09	72.57	
LOSS				8.58	.06	
PRODUCTS		99320.0	107.28	14113.74	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA SPLITTER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
PROD FRACT OV:JP-8	.6524	22993.1	100.00	2626.40	100.00	
CHARGE		22993.1	100.00	2626.40	100.00	
PRODUCTS						
SPLITTER GAS=JP-8				42.81	1.63	887.76
SPLIT OV LIQ=JP-8	.6197	16633.9	72.34	1804.78	68.72	
SPLITTER BOTTOMS	.7620	5837.5	25.39	778.81	29.65	
PRODUCTS		22471.4	97.73	2626.40	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
DEBUTANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLIT OV LIQ=JP-8	.6197	16633.9	100.00	1804.78	100.00	
CHARGE		16633.9	100.00	1804.78	100.00	
PRODUCTS						
DEBUT OVER'D=JP-8	.5458	6263.9	37.66	598.59	33.17	8864.78
LT NAPHTHA JP-8	.6643	10370.6	62.35	1206.19	66.83	
PRODUCTS		16634.5	100.00	1804.78	100.00	

DETAILED MATERIAL BALANCE
DEPROPANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEBUT OVER'D=JP-8	.5458	1229.3	100.00	117.47	100.00	1739.69
CHARGE		1229.3	100.00	117.47	100.00	
PRODUCTS						
DEPROP OV'D JP-8				32.95	28.05	637.45
MIXED C4'S:JP-8	.5743	840.6	68.38	84.52	71.95	
PRODUCTS		840.6	68.38	117.47	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
FUEL GAS TREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
LP FLASH GAS:JP-8				596.03	50.67	29761.69
DEBUT OVER'D=JP-8	.5458	5034.7	100.00	481.12	40.90	7125.09
SPLITTER GAS=JP-8				42.81	3.64	887.76
DEPROP OV'D JP-8				32.95	2.80	637.45
NAP HYDROTREAT GAS				.93	.08	102.21
F.O. STAB OVER'D				22.54	1.92	1235.32
CHARGE		5034.7	100.00	1176.39	100.00	
PRODUCTS						
HYDROGEN SULFIDE				18.63	1.58	414.81
TRT LP FLASH:JP-8				585.36	49.76	29520.27
TRT DEB OV'D=JP-8				476.74	40.53	7027.35
TRT SPLIT GAS=JP-8				41.90	3.56	867.76
TRT DEP OV'D-JP8				31.88	2.71	613.61
TRT NAP HTRT GAS				.93	.08	102.21
TRT F.O. STAB OV'D				20.94	1.78	1199.58
PRODUCTS				1176.39	100.00	

DETAILED MATERIAL BALANCE
SULFUR PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.20	100.00	2186.99
CHARGE				98.20	100.00	
PRODUCTS						
SULFUR				87.77	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.20	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
HYDROGEN PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEBUT OVERHEAD-100R	.5349	289.2	23.27	27.09	1.96	531.26
TRT LP FLASH:JP-8				585.36	42.40	29520.27
TRT DEB OV'D=JP-8				476.74	34.54	7027.35
TRT SPLIT GAS=JP-8				41.90	3.04	867.76
TRT DEP OV'D-JP8				31.88	2.31	613.61
TRT NAP HTRT GAS				.93	.07	102.21
TRT F.O. STAB OV'D				20.94	1.52	1199.58
PLAT NET SEP GAS-100				73.17	5.30	8929.54
PLAT DEBUT GAS-100R				11.44	.83	285.78
LT NAPHTHA JP-8	.6643	954.0	76.73	110.96	8.04	
CHARGE		1243.3	100.00	1380.43	100.00	
PRODUCTS						
HYDROGEN (97%)				752.27	54.50	234287.62
CO2--HYD.PLT.				628.16	45.50	
PRODUCTS				1380.43	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA HYDROTREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLITTER BOTTOMS	.7620	5837.5	97.09	778.81	96.14	
HYDROGEN (97%)				.55	.07	169.79
COLD TREATED WATER	1.0000	175.3	2.91	30.68	3.79	
CHARGE		6012.7	100.00	810.04	100.00	
PRODUCTS						
NAP HYDROTREAT GAS				.93	.12	102.21
SOUR WATER-NAP HT	1.0000	175.3	2.91	30.68	3.79	
TRT HC HVY NAPHTHA	.7616	5837.6	97.09	778.42	96.10	
PRODUCTS		6012.9	100.00	810.04	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
UOP PLATFORMING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT HC HVY NAPHTHA	.7616	5837.6	100.00	778.42	100.00	
CHARGE		5837.6	100.00	778.42	100.00	
PRODUCTS						
PLAT NET SEP GAS-100				73.17	9.40	8928.54
PLAT DEBUT GAS-100R				11.44	1.47	285.78
DEBUT OVERHEAD-100R	.5349	289.2	4.95	27.09	3.48	531.26
100 RON PLATFORMATE	.8233	4625.2	79.23	666.71	85.65	
PRODUCTS		4914.5	84.19	778.42	100.00	

DETAILED MATERIAL BALANCE
SOUR WATER TREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SOUR WATER - L.P.HT	1.0000	3558.4	19.85	623.02	19.85	
SOUR WATER - H.P.HT	1.0000	10535.1	58.76	1844.54	58.76	
SOUR WATER (HC)	1.0000	3659.0	20.41	640.63	20.41	
SOUR WATER-NAP HT	1.0000	175.3	.98	30.68	.98	
CHARGE		17927.7	100.00	3138.88	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	16231.9	90.54	2841.97	90.54	
AMMONIA				291.34	9.28	
LOSS				5.57	.18	
PRODUCTS		16231.9	90.54	3138.88	100.00	

DETAILED MATERIAL BALANCE
AMINE REGENERATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
[illegible] SULFIDE				98.20	100.00	2186.99
[illegible]				98.20	100.00	
[illegible] FIDE				98.20	100.00	2186.99
[illegible]				98.20	100.00	

AD-A130 374 USAF SHALE OIL TO FUELS VOLUME 2 PHASES 3 AND 4(U) UOP INC DES PLAINES IL PROCESS DIV J G SIKONIA ET AL. JUL 82 AFWAL-TR-81-2116-VOL-2 F33615-78-C-2079 4/4

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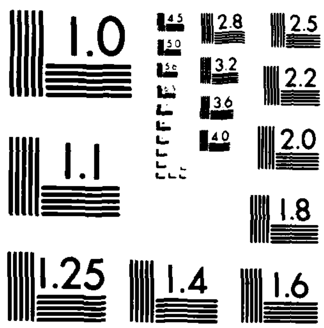

MICROCOPY RESOLUTION TEST CHART
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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
AMMONIA PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
AMMONIA				291.34	100.00	
CHARGE				291.34	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.8		14.66	5.03	
ANHYDRUS AMMONIA				276.68	94.97	
PRODUCTS		83.8		291.34	100.00	

DETAILED MATERIAL BALANCE
FUEL OIL STABILIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	8458.7	100.00	1240.63	100.00	
CHARGE		8458.7	100.00	1240.63	100.00	
PRODUCTS						
F.O. STAB OVER'D				22.54	1.82	1235.32
F.O. STAB BOTTOMS	.8640	8052.2	95.19	1218.09	98.18	
PRODUCTS		8052.2	95.19	1240.63	100.00	

DETAILED MATERIAL BALANCE
COMBINED FACILITIES
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
UOP PLATFORMING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT HC HVY NAPHTHA	.7616	5837.6	100.00	778.42	100.00	
CHARGE		5837.6	100.00	778.42	100.00	
PRODUCTS						
PLAT NET SEP GAS-100				73.17	9.40	8928.54
PLAT DEBUT GAS-100R				11.44	1.47	285.78
DEBUT OVERHEAD-100R	.5349	289.2	4.95	27.09	3.48	531.26
100 RON PLATFORMATE	.8233	4625.2	79.23	666.71	85.65	
PRODUCTS		4914.5	84.19	778.42	100.00	

DETAILED MATERIAL BALANCE
SOUR WATER TREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SOUR WATER - L.P.HT	1.0000	3558.4	19.85	623.02	19.85	
SOUR WATER - H.P.HT	1.0000	10535.1	58.76	1844.54	58.76	
SOUR WATER (HC)	1.0000	3659.0	20.41	640.63	20.41	
SOUR WATEP-NAP HT	1.0000	175.3	.98	30.68	.98	
CHARGE		17927.7	100.00	3138.88	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	16231.9	90.54	2841.97	90.54	
AMMONIA				291.34	9.28	
LOSS				5.57	.18	
PRODUCTS		16231.9	90.54	3138.88	100.00	

DETAILED MATERIAL BALANCE
AMINE REGENERATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.20	100.00	2186.99
CHARGE				98.20	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.20	100.00	2186.99
PRODUCTS				98.20	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE
DUMMY UNIT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
MIXED BUTANES	.5743	840.6	100.00	84.52	100.00	
CHARGE		840.6	100.00	84.52	100.00	
PRODUCTS						
MIXED BUTANES	.5743	840.6	100.00	84.52	100.00	
PRODUCTS		840.6	100.00	84.52	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
ELECTRIC POWER   UNIT IS KWH   PRICE IS .04500/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	7.0969	48.387	638483.09	28731.74
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.3911	3.424	8993.59	404.71
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.1399	1.289	2327.09	104.72
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.1200	1.256	147.51	6.64
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		21.974	2157.87	97.10
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		233.790	175873.57	7914.31
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.7065	5.296	4124.25	185.59
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	2.4382	18.285	14233.36	640.50
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	.3787	2.163	6788.77	305.49
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		40.773	4003.95	180.18
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68		3.393	938.71	42.24
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63	.1638	1.116	1385.16	62.33
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							1158228.20	52120.27

Appendix B.7 (Cont.)

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
600# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0075	.051	676.92	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		.220	21.57	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		-5.317	-3999.61	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	-.0603	-.452	-351.77	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							-457.81	
AMOUNT PRODUCED FROM REFINERY FUELS							4151.38	2830.48
AMOUNT CONVERTED TO 150# STEAM							4141.01	
AMOUNT CONVERTED TO 50# STEAM							468.17	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0398	.271	3578.58	107.36
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.0299	.261	686.80	20.60
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.0116	.107	192.39	5.77
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.0857	.897	105.33	3.16
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		.806	606.02	18.18
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.0118	.089	69.16	2.07
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.0848	.636	494.92	14.85
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	.1336	.763	2395.10	71.85
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		32.389	3180.63	95.42
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68		10.961	3032.67	90.98
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63	.0200	.137	169.59	5.09
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							14657.06	439.71

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
REFINERY FUELS . UNIT IS MMBTU
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.1729	1.179	15553.35	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.0640	.560	1472.10	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		57.884	43544.29	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.0170	.127	99.06	
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.3238	2.428	1890.31	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63	.0486	.331	411.27	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							69398.32	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							42754.91	
AMOUNT PRODUCED FROM LT NAPHTHA JP-8							30417.39	
AMOUNT CONVERTED TO 600# STEAM							3773.98	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
150# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		-7.593	-745.65	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.0007	.005	4.05	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	.2633	1.504	4719.58	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		1.660	163.03	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							4141.01	
AMOUNT PRODUCED FROM 600# STEAM							4141.01	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
50# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	-.0031	-.021	-278.62	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.0460	.424	765.41	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.0276	.289	33.93	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		-9.864	-968.63	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		9.327	915.88	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							468.17	
AMOUNT PRODUCED FROM 600# STEAM							468.17	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
BOILER WATER UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0112	.076	1006.80	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		18.946	1860.52	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		17.088	12854.46	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.0987	.740	576.18	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.68				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							16297.97	
AMOUNT PURCHASED							5560.86	2780.43
AMOUNT PRODUCED FROM CONDENSATE							10737.11	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY
CONDENSATE UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.	14441.92	-.0193	-.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.	14390.21	-.0158	-.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	-.0075	-.051	-676.92	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	-.0460	-.424	-765.41	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	-.0276	-.289	-33.93	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		-.684	-67.13	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	-.0343	-.257	-200.13	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	-.2633	-1.504	-4719.58	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		-10.987	-1078.94	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							-10737.11	
AMOUNT CONVERTED TO BOILER WATER							10737.11	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY
CAT. & CHEMICALS UNIT IS $ PRICE IS 1.00000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0699	.477	6290.22	6290.22
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		5.019	3775.87	3775.87
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.0028	.021	16.59	16.59
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.0569	.426	331.99	331.99
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		.283	27.75	27.75
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							24609.08	24609.08

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STEAM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STEAM MLBS	50# STEAM MLBS	BOILER WATER MLBS	CONDENSATE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	638483.1	676.9	3578.6	15553.4		-278.4	1006.8	-676.9
NAPHTHA SPLITTER	8993.6		686.8	1472.1				
DEBUTANIZER	2327.1		192.4			765.4		-765.4
DEPROPANIZER	147.5		105.3			33.9		-33.9
SULFUR PLANT	2157.9	21.6			-745.7	-968.6	1860.5	-67.1
HYDROGEN PLANT	175873.6	-3999.6	606.0	43544.3			12854.5	
NAPHTHA HYDROTREATER	4124.2		69.2	99.1				
UOP PLATFORMING	14233.4	-351.8	494.9	1890.3	4.0		576.2	-200.1
SOUR WATER TREATING	6788.8		2195.1		4719.6			-4719.6
AMINE REGENERATION	4004.0		3180.6		163.0	915.9		-1078.9
AMMONIA PLANT	938.7		3032.7					
FUEL OIL STABILIZER	1385.2		169.6	411.3				
TOTAL CONSUMPTION	1158228.2	-457.8	14657.1	69398.3	4141.0	468.2	16298.0	-10737.1

USAF SHALE OIL TO FUELS
PHASE IV
CASE 3 - MAXIMUM JP-8 JET FUEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & C HEMICALS $
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	6290.2
NAPHTHA SPLITTER	
DEBUTANIZER	
DEPROPANIZER	
SULFUR PLANT	
HYDROGEN PLANT	3775.9
NAPHTHA HYDROTREATER	16.6
UOP PLATFORMING	332.0
SOUR WATER TREATING	
AMINE REGENERATION	27.8
AMMONIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	24609.1

Appendix B.8

JP-8 PLUS DIESEL CASE -- STANDARD OPTIMIZATION REPORT

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	QUANTITY LIMITS MAXIMUM	MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL $/DAY
	A	UNLEADED GASOLINE				3169.30 BBL	58.8500	186573.30
	A	AV TURBINE FUEL JP-8				49697.18 BBL	58.8500	2924679.04
	A	DF-2/DF-M DIESEL				26894.99 BBL	58.8500	1582770.16
	A	SULFUR				87.75 TON	95.4500	8376.17
	A	ANHYDRUS AMMONIA				275.88 TON	155.0000	42761.61
	TOTAL SALES REVENUE							4745100.78

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS			QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL			90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER				14504.43 BBL	.0245	355.36
	508 STRIPPING STEAM				159.99 TON	.0000	.00
TOTAL RAW MATERIAL COST							3600355.36
GROSS MARGIN							1144744.92

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	OPERATING COST $/BBL	OPERATING COST $/TON	OPERATING COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84888.1	12450.46	.627371	4.27746	53256.34
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11848.5	1338.05	.081956	.72571	971.03
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8676.8	933.38	.110762	1.02965	961.06
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	635.9	60.19	.828065	8.74930	526.59
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		766.39		.92290	707.30
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		19.67483	1931.70
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		715.82		38.80267	27775.71
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	2588.2	345.31	.530560	3.97677	1373.20
UOP PLATFORMING	COMBINED MODES	COMPOSITE COST	2588.3	345.13	1.184450	8.88260	3065.68
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17623.6	3085.64	.207060	1.18263	3649.15
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		17.81405	1749.01
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.88		2.68881	741.79
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13537.4	1985.51	.077477	.52824	1048.83
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57
DUMMY UNIT	COMBINED MODES	COMPOSITE COST	405.4	40.78			

TOTAL PROCESS UNIT OPERATING COST 157848.21

UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D
	BOILER WATER	MLBS	9824.12	.50000	4912.06

TOTAL UTILITY PURCHASES 4912.06

UTILITY SALES	UTILITY	UNIT	UNITS/D	$/UNIT	$/D
	50# STEAM	MLBS	625.78	.00010	.06

TOTAL UTILITY SALES .06

UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D	SOURCE	$/D
	600# STEAM	MLBS	754.67	REFINERY FUELS	514.55

TOTAL UTILITY PRODUCTION COSTS 514.55

TOTAL OPERATING COST 163274.76

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	CAPITAL COST $/BBL	CAPITAL COST $/TON	CAPITAL COST $/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84888.1	12450.46	1.908267	13.01071	161989.29
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11848.5	1338.05	.130502	1.15560	1546.25
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8676.8	933.38	.314447	2.92312	2728.40
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	635.9	60.19	1.035242	10.93832	658.33
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		766.39		1.56139	1196.64
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		57.38291	5633.94
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		715.82		163.08393	116738.64
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	2588.2	345.31	.775609	5.81350	2007.44
UOP PLATFORMING	COMBINED MODES	COMPOSITE COST	2588.3	345.13	2.291712	17.18633	5931.57
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17623.6	3085.64	.529845	3.02621	9337.79
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		26.64689	2616.23
AMMONIA PLANT	COMBINED MODES	COMPOSITE COST		275.88		1.50753	415.90
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13537.4	1985.51	.214207	1.46048	2899.80
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10371.11
DUMMY UNIT	COMBINED MODES	COMPOSITE COST	405.4	40.78			
TOTAL							482155.78

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

MATERIAL BALANCE SUMMARY

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	86.121	14441.92	84.252	
COLD TREATED WATER	1.00000	14504.4	13.879	2539.51	14.815	
50# STRIPPING STEAM				159.99	.933	
TOTAL CHARGE		104504.4	100.000	17141.42	100.000	

PRODUCTS	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
UNLEADED GASOLINE	.76091	3169.3	3.033	422.23	2.463	
AV TURBINE FUEL JP-8	.80500	49697.2	47.555	7004.50	40.863	
DF-2/DF-M DIESEL	.83580	26895.0	25.736	3935.71	22.960	
SULFUR				87.75	.512	
ANHYDRUS AMMONIA				275.88	1.609	
TOTAL PRODUCTS SOLD		79761.5	76.324	11726.08	68.408	

STREAMS CONVERTED TO UTILITIES	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	12886.8	12.331	1949.44	11.373	
TOTAL STREAMS CONVERTED		12886.8	12.331	1949.44	11.373	

STREAMS NOT UTILIZED	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LOSS				27.04	.158	
SULFUR PLANT LOSS				10.43	.061	
CO2--HYD.PLT.				624.23	3.642	
TREATED SOUR WATER	1.00000	16016.2	15.326	2804.20	16.359	
TOTAL NOT UTILIZED		16016.2	15.326	3465.90	20.219	
TOTAL PRODUCTS MADE		108664.5	103.981	17141.42	100.000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY	CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY	BBLS/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY	BBLS/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY	BBLS/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY	BBLS/CD				84887.5	84887.5	168931683
NAPHTHA SPLITTER	CAPACITY	BBLS/CD				11849.6	11849.6	1612516
DEBUTANIZER	CAPACITY	BBLS/CD				8677.4	8677.4	2845328
DEPROPANIZER	CAPACITY	BBLS/CD				636.0	636.0	686548
FUEL GAS TREATER	CAPACITY	TONS/CD				766.4	766.4	1247922
SULFUR PLANT	CAPACITY	TONS/CD				98.2	98.2	5875389
HYDROGEN PLANT	CAPACITY	TONS/CD				715.8	715.8	121741719
NAPHTHA HYDROTREATER	CAPACITY	BBLS/CD				2588.2	2588.2	2093469
UOP PLATFORMING	CAPACITY	BBLS/CD				2479.6	2479.6	6185784
SOUR WATER TREATING	CAPACITY	BBLS/CD				17714.1	17714.1	9737981
AMINE REGENERATION	CAPACITY	TONS/CD				98.2	98.2	2728353
AMMONIA PLANT	CAPACITY	TONS/CD				275.9	275.9	433723
FUEL OIL STABILIZER	CAPACITY	BBLS/CD				13537.2	13537.2	3024072
COMBINED FACILITIES	CAPACITY	BBLS/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT								502809487

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PRODUCT BLENDING

UNLEADED GASOLINE	BBL/D	TONS/D	SPGR@60F	WT% SULF	RES OCTN	MOT OCTN	(R+M)/2	RVP INDX	VL% AROM	D+L 131F
SPLITTER BOTTOMS	251.6	33.56	.7620	.0003	59.0000	57.0000	58.0000	3.1000	7.0000	.0000
LT NAPHTHA JP-8 DM	409.0	47.44	.6625	.0003	75.0000	73.0000	74.0000	175.0000	2.0000	51.0000
98 RON PLATFORMATE	2103.1	300.44	.8159	.0003	98.0000	87.0000	92.5000	53.3000	68.6000	.5000
MIXED BUTANES	405.6	40.78	.5743	.0003	98.5000	94.3000	96.4000	1280.0000	.0000	100.0000
BLEND	3169.3	422.23	.7609	.0003	92.0000	83.7461	87.8730	222.0000	46.3350	19.7104
SPECIFICATIONS		MAX		.1000				222.0000	55.0000	
		MIN			92.0000	82.0000	87.0000			10.0000

PRODUCT BLENDING

UNLEADED GASOLINE	BBL/D	TONS/D	D+L 171F	D+L 235F	D+L 365F	D+L 437F
SPLITTER BOTTOMS	251.6	33.56	1.0000	41.0000	100.0000	100.0000
LT NAPHTHA JP-8 DM	409.0	47.44	96.0000	100.0000	100.0000	100.0000
98 RON PLATFORMATE	2103.1	300.44	6.0000	40.0000	100.0000	100.0000
MIXED BUTANES	405.6	40.78	100.0000	100.0000	100.0000	100.0000
BLEND	3169.3	422.23	29.2471	55.5008	100.0000	100.0000
SPECIFICATIONS		MAX	50.0000			100.0000
		MIN		50.0000	90.0000	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	SPGR@60F	WT% SULF	VL% AROM	SMOKE PT	FREEZ PT	VL% NAPH	FLASH PT	D+L 401F
HC KEROSINE:300-550F	49697.2	7004.50	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
BLEND	49697.2	7004.50	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
SPECIFICATIONS		MAX	.8398	.4000	25.0000		-58.0000	3.0000		
		MIN	.7753			20.0000			100.0000	10.0000

PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	D+L 572F
HC KEROSINE:300-550F	49697.2	7004.50	100.0000
BLEND	49697.2	7004.50	100.0000
SPECIFICATIONS		MAX	100.0000
		MIN	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	SPGR@60F	WT% SULF	FLASH PT	CETANE I	D+L 700F	VIS 100F	POUR PT.	CLOUD PT
HC DIESEL:550-700F	26895.0	3935.71	.8358	.0003	288.0000	56.0000	100.0000	18.4000	.0000	5.0000
BLEND	26895.0	3935.71	.8358	.0003	288.0000	56.0000	100.0000	18.4000	.0000	5.0000
SPECIFICATIONS		MAX	.8607	.7000			100.0000	18.4100	.0000	5.0000
		MIN	.8203		133.0000	45.0000		10.3100		

PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	D+L 675F	D+L 725F
HC DIESEL:550-700F	26895.0	3935.71	90.0000	100.0000
BLEND	26895.0	3935.71	90.0000	100.0000
SPECIFICATIONS		MAX		100.0000
		MIN	90.0000	

PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR@60F
SULFUR		87.75	
BLEND		87.75	
NO SPECIFICATIONS			

PRODUCT BLENDING

ANHYDRUS AMMONIA	BBL/D	TONS/D	SPGR@60F
ANHYDRUS AMMONIA		275.88	
BLEND		275.88	
NO SPECIFICATIONS			

RECYCLE STREAM BLENDING

MIXED BUTANES	BBL/D	TONS/D	SPGR@60F
MIXED C4'S:JP-8 DM	343.6	34.55	.5744
MIXED C4'S-98R PLT	61.8	6.23	.5756
BLEND	405.4	40.78	.5746
NO SPECIFICATIONS			

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR@60F
F.O. STAB BOTTOMS	12886.8	1949.44	.8640
BLEND	12886.8	1949.44	.8640

NO SPECIFICATIONS

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
FEED PREPARATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE
L.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.HT	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.18
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE
H.P. HYDROTREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.HT	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(HP)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
HYDROCRACKING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	84888.1	97.18	12450.46	93.63	
HYDROGEN (97%)				255.73	1.92	79645.39
COLD TREATED WATER	1.0000	2462.6	2.82	431.16	3.24	
50# STRIPPING STEAM				159.99	1.20	
CHARGE		87350.7	100.00	13297.34	100.00	
PRODUCTS						
LP FLASH GAS:JP8-DM				406.51	3.06	25083.83
PROD FRACT OV:JP8-DM	.6450	11848.5	13.56	1338.05	10.06	
SOUR WATER (HC)	1.0000	3452.4	3.95	604.47	4.55	
HC KEROSINE:300-550F	.8050	49697.2	56.89	7004.50	52.68	
HC DIESEL:550-700F	.8358	26895.0	30.79	3935.71	29.60	
LOSS				8.09	.06	
PRODUCTS		91893.1	105.20	13297.34	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA SPLITTER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
PROD FRACT OV:JP8-DM	.6450	11848.5	100.00	1338.05	100.00	
CHARGE		11848.5	100.00	1338.05	100.00	
PRODUCTS						
SPLITTER GAS=JP8-DM				25.80	1.93	601.35
SPLIT OV LIQ=JP8-DM	.6144	8676.8	73.23	933.38	69.76	
SPLITTER BOTTOMS	.7620	2839.8	23.97	378.87	28.31	
PRODUCTS		11516.6	97.20	1338.05	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
DEBUTANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLIT OV LIQ=JP8-DM	.6144	8676.8	100.00	933.38	100.00	
CHARGE		8676.8	100.00	933.38	100.00	
PRODUCTS						
DEBUT OVER'D=JP8-DM	.5418	3457.2	39.84	327.95	35.14	4972.24
LT NAPHTHA JP-8 DM	.6625	5219.5	60.15	605.43	64.86	
PRODUCTS		8676.7	100.00	933.38	100.00	

DETAILED MATERIAL BALANCE
DEPROPANIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
DEBUT OVER'D=JP8-DM	.5418	524.6	82.49	49.76	82.68	754.48
DEBUT OVFRHEAD-98R	.5347	111.3	17.51	10.42	17.32	204.42
CHARGE		635.9	100.00	60.19	100.00	
PRODUCTS						
DEPROP OV'D JP-8 DM				15.21	25.27	303.93
MIXED C4'S:JP-8 DM	.5744	343.6	54.03	34.55	57.41	
DEPROP OV'D-98R PLT				4.20	6.97	79.68
MIXED C4'S-98R PLT	.5756	61.8	9.72	6.23	10.35	
PRODUCTS		405.4	63.75	60.19	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
FUEL GAS TREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
LP FLASH GAS:JP8-DM				406.51	53.04	25083.83
DEBUT OVER'D=JP8-DM	.5418	2932.6	100.00	278.19	36.30	4217.77
SPLITTER GAS=JP8-DM				25.80	3.37	601.35
DEPROP OV'D JP-8 DM				15.21	1.98	303.93
NAP HYDROTREAT GAS				.41	.05	45.32
F.O. STAB OVER'D				36.08	4.71	1977.01
DEPROP OV'D-98R PLT				4.20	.55	79.68
CHARGE		2932.6	100.00	766.39	100.00	
PRODUCTS						
HYDROGEN SULFIDE				18.61	2.43	414.38
TRT LP FLASH=JP8-DM				396.47	51.73	24848.09
TRT DEB OV'D=JP8-DM				273.82	35.73	4120.27
TRT SPLIT GAS=JP8-DM				24.94	3.25	582.28
TRT DEP OV'D-JP8 DM				14.43	1.88	286.53
TRT NAP HTRT GAS				.41	.05	45.32
TRT F.O. STAB OV'D				33.52	4.37	1919.81
TRT DEPRO OV-98R PLT				4.20	.55	79.68
PRODUCTS				766.39	100.00	

DETAILED MATERIAL BALANCE
SULFUR PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.18	100.00	2186.55
CHARGE				98.18	100.00	
PRODUCTS						
SULFUR				87.75	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.18	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
HYDROGEN PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT LP FLASH=JP8-DM				396.47	29.59	24848.09
TRT DEB OV'D=JP8-DM				273.82	20.43	4120.27
TRT SPLIT GAS=JP8-DM				24.94	1.86	582.28
TRT DEP OV'D-JP8 DM				14.43	1.08	286.53
TRT DEPRO OV-98R PLT				4.20	.31	79.68
TRT NAP HTRT GAS				.41	.03	45.32
TRT F.O. STAB OV'D				33.52	2.50	1919.81
PLAT NET SEP GAS-98R				29.09	2.17	3742.77
PLAT DEBUT GAS-98R				5.18	.39	129.46
LT NAPHTHA JP-8 DM	.6625	4810.5	100.00	557.99	41.64	
CHARGE		4810.5	100.00	1340.05	100.00	
PRODUCTS						
HYDROGEN (97%)				715.82	53.42	222935.00
CO2--HYD.PLT.				624.23	46.58	
PRODUCTS				1340.05	100.00	

DETAILED MATERIAL BALANCE
NAPHTHA HYDROTREATER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SPLITTER BOTTOMS	.7620	2588.2	97.09	345.31	96.14	
HYDROGEN (97%)				.24	.07	75.28
COLD TREATED WATER	1.0000	77.7	2.91	13.61	3.79	
CHARGE		2665.9	100.00	359.15	100.00	
PRODUCTS						
NAP HYDROTREAT GAS				.41	.12	45.32
SOUR WATER-NAP HT	1.0000	77.7	2.91	13.61	3.79	
TRT HC HVY NAPHTHA	.7616	2588.3	97.09	345.13	96.10	
PRODUCTS		2666.0	100.00	359.15	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
UOP PLATFORMING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
TRT HC HVY NAPHTHA	.7616	2588.3	100.00	345.13	100.00	
CHARGE		2588.3	100.00	345.13	100.00	
PRODUCTS						
PLAT NET SEP GAS-98R				29.09	8.43	3742.77
PLAT DEBUT GAS-98R				5.18	1.50	129.46
DEBUT OVERHEAD-98R	.5347	111.3	4.30	10.42	3.02	204.42
98 RON PLATFORMATE	.8159	2103.1	81.26	300.44	87.05	
PRODUCTS		2214.5	85.56	345.13	100.00	

DETAILED MATERIAL BALANCE
SOUR WATER TREATING
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SOUR WATER - L.P.HT	1.0000	3558.4	20.19	623.02	20.19	
SOUR WATER - H.P.HT	1.0000	10535.1	59.78	1844.54	59.78	
SOUR WATER (HC)	1.0000	3452.4	19.59	604.47	19.59	
SOUR WATER-NAP HT	1.0000	77.7	.44	13.61	.44	
CHARGE		17623.6	100.00	3085.64	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15932.7	90.41	2789.58	90.41	
AMMONIA				290.50	9.41	
LOSS				5.55	.18	
PRODUCTS		15932.7	90.41	3085.64	100.00	

DETAILED MATERIAL BALANCE
AMINE REGENERATION
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
HYDROGEN SULFIDE				98.18	100.00	2186.55
CHARGE				98.18	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.18	100.00	2186.55
PRODUCTS				98.18	100.00	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
AMMONIA PLANT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
AMMONIA				290.50	100.00	
CHARGE				290.50	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.5		14.62	5.03	
ANHYDRUS AMMONIA				275.88	94.97	
PRODUCTS		83.5		290.50	100.00	

DETAILED MATERIAL BALANCE
FUEL OIL STABILIZER
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
SEPARATOR LIQUID(HP)	.8377	13537.4	100.00	1985.51	100.00	
CHARGE		13537.4	100.00	1985.51	100.00	
PRODUCTS						
F.O. STAB OVER'D				36.08	1.82	1977.01
F.O. STAB BOTTOMS	.8640	12886.8	95.19	1949.44	98.18	
PRODUCTS		12886.8	95.19	1985.51	100.00	

DETAILED MATERIAL BALANCE
COMBINED FACILITIES
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE
DUMMY UNIT
COMPOSITE YIELDS

	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
CHARGE						
MIXED BUTANES	.5746	405.4	100.00	40.78	100.00	
CHARGE		405.4	100.00	40.78	100.00	
PRODUCTS						
MIXED BUTANES	.5743	405.6	100.05	40.78	100.00	
PRODUCTS		405.6	100.05	40.78	100.00	

Appendix B.8 (Cont.)

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
ELECTRIC POWER   UNIT IS KWH   PRICE IS   .04500/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	6.1047	41.622	518213.05	23319.59
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.3912	3.464	4634.74	208.56
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.1399	1.301	1213.96	54.63
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.1200	1.268	76.32	3.43
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		21.974	2157.44	97.08
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		211.850	151646.10	6824.07
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.7065	5.296	1828.60	82.29
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	2.3309	17.480	6032.93	271.48
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	.3787	2.163	6674.09	300.33
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		40.773	4003.15	180.14
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88		3.393	936.01	42.12
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51	.1638	1.116	2216.83	99.76
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							998406.69	44928.20

Appendix B.8 (Cont.)

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
600# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		.220	21.57	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		-6.694	-4791.42	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	-.0603	-.452	-155.97	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							-1730.74	
AMOUNT PRODUCED FROM REFINERY FUELS							754.67	514.55
AMOUNT CONVERTED TO 150# STEAM							2485.42	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0263	.179	2228.63	66.86
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.0299	.264	353.91	10.62
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.0116	.107	100.34	3.01
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.0857	.905	54.50	1.63
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		.535	382.75	11.48
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0118	.089	30.66	.92
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0800	.600	207.08	6.21
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	.1336	.763	2354.64	70.64
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		32.389	3180.00	95.40
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88		10.961	3023.94	90.72
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51	.0200	.137	271.42	8.14
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							12333.74	370.01

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
REFINERY FUELS. UNIT IS MMBTU
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.1721	1.173	14609.37	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.0640	.567	758.67	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		62.082	44439.69	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0170	.127	43.92	
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2589.3	345.13	.3096	2.322	801.40	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3095.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51	.0486	.331	658.20	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							67739.19	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							68425.25	
AMOUNT CONVERTED TO 600# STEAM							686.07	

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
150# STEAM UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84688.1	12450.46	-.0185	-.126	-1573.74	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-7.593	-745.50	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0007	.005	1.79	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	.2633	1.504	4639.86	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		1.660	163.00	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1995.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							2485.42	
AMOUNT PRODUCED FROM 600# STEAM							2485.42	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
50# STEAM   UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	-.0117	-.079	-989.81	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.0460	.428	399.21	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.0276	.292	17.55	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-9.864	-968.43	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		9.327	915.70	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							-625.78	
AMOUNT SOLD							625.78	.06

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
BOILER WATER UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0390	.266	3314.31	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		18.946	1860.15	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		19.391	13880.46	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0939	.706	242.94	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							19297.86	
AMOUNT PURCHASED							9824.12	4912.06
AMOUNT PRODUCED FROM CONDENSATE							9473.74	

Appendix B.8 (Cont.)

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY
CONDENSATE UNIT IS MLBS
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	-.0193	-.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-.0158	-.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	-.0460	-.428	-399.21	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	-.0276	-.292	-17.55	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-.684	-67.12	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	-.0294	-.221	-76.21	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	-.2633	-1.504	-4639.86	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		-10.987	-1078.72	
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							-9473.74	
AMOUNT CONVERTED TO BOILER WATER							9473.74	

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JF-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY
CAT. & CHEMICALS UNIT IS $ PRICE IS 1.00000/UNIT
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0578	.394	4910.46	4910.46
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		5.191	3715.56	3715.56
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0028	.021	7.36	7.36
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0435	.326	112.55	112.55
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		.283	27.75	27.75
AMMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1935.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							22940.33	22940.33

USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STEAM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STEAM MLBS	50# STEAM MLBS	BOILER WATER MLBS	CONDENSATE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	518213.0		2228.6	14609.4	-1573.7	-989.8	3314.3	
NAPHTHA SPLITTER	4634.7		353.9	758.7				
DEBUTANIZER	1214.0		100.3			399.2		-399.2
DEPROPANIZER	76.3		54.5			17.6		-17.6
SULFUR PLANT	2157.4	21.6			-745.5	-968.4	1860.1	-67.1
HYDROGEN PLANT	151646.1	-4791.4	382.8	44439.7			13880.5	
NAPHTHA HYDROTREATER	1828.6		30.7	43.9				
UOP PLATFORMING	6032.9	-156.0	207.1	801.4	1.8		242.9	-76.2
SOUR WATER TREATING	6674.1		2354.6		4639.9			-4639.9
AMINE REGENERATION	4003.2		3180.0		163.0	915.7		-1078.7
AMMONIA PLANT	936.0		3023.9					
FUEL OIL STABILIZER	2216.8		271.4	658.2				
TOTAL CONSUMPTION	998404.5	-1730.7	12333.7	67739.2	2485.4	-625.8	19297.9	-9473.7

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USAF SHALE OIL TO FUELS
PHASE IV
CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & C HEMICALS $
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	4910.5
NAPHTHA SPLITTER	
DEBUTANIZER	
DEPROPANIZER	
SULFUR PLANT	
HYDROGEN PLANT	3715.6
NAPHTHA HYDROTREATER	7.4
UOP PLATFORMING	112.5
SOUR WATER TREATING	
AMINE REGENERATION	27.7
AMMONIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	22940.3

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